NATIONAL ENERGY TECHNOLOGY LABORATORY

Cost and Performance of Retrofitting Existing NGCC Units for Carbon Capture

October 1, 2010

DOE/NETL- 401/080610

U.S. DEPARTMENT OF ENERGY

Disclaimer

COST AND PERFORMANCE OF RETROFITTING EXISTING NGCC UNITS FOR CARBON CAPTURE

DOE/NETL-401/080610

FINAL REPORT

October 1, 2010

NETL Contact:

Eric Grol
Chemical Engineer
Office of Systems, Analyses and Planning

National Energy Technology Laboratory

www.netl.doe.gov

ACKNOWLEDGEMENTS

This analysis was a team effort, with numerous individuals generously donating their time to answer questions and provide reviews. The contributions of John Wimer, Kristin Gerdes, and Mike Matuszewski are especially noted.

This page intentionally left blank

Table of Contents

List of Figures

List of Tables

1. Summary

This analysis is an evaluation of the cost and performance associated with retrofitting existing natural gas combined cycle (NGCC) plants for carbon capture and sequestration (CCS). The NGCC considered is based on the use of a GE 7EA (1979) combustion turbine. The strategy for capturing CO_2 from NGCC plants is assumed to be a post-combustion approach, using an Econamine scrubber.

1.1 EFFECT OF CO_2 TAX ON NGCC LEVELIZED COST OF ELECTRICITY

Part of possible climate change legislation may include provisions whereby plants are taxed on every ton of CO_2 that is emitted. Units that emit less CO_2 (whether by burning a low-carbon fuel or through CCS) will have lower operating costs because they emit less carbon dioxide. Therefore under a carbon tax scenario, there is an incentive for plants to control the amount of CO_2 that is emitted because it keeps costs low.

In this analysis, NGCC plants that retrofitted for CO_2 capture actually experienced an increase in first year cost of electricity[1] (COE) as CCS levels increased, when the carbon tax was below the plant's avoided cost of 90% CO_2 capture ($65/tonne CO_2 and $72/tonne CO_2 for Midwestern and western NGCC units, respectively)[2]. ***Therefore, this analysis finds that existing NGCC units have no incentive to retrofit for CCS until the carbon tax reaches the plant's avoided cost of 90% CO_2 capture. When the tax exceeds this level, plants can minimize their COE by capturing as much CO_2 as possible (in this analysis, 90%). This analysis further concludes that if an NGCC unit will be retrofit, COE is minimized when CCS is maximized.***

Since natural gas has a low carbon intensity (relative to coal), the portion of COE attributable to the CO_2 tax is small when the price of carbon is low (the carbon intensity of coal is approximately 2.1 lb CO_2/kWh generated; for natural gas, the same metric is approximately 1.3 lb CO_2/kWh generated[i]). NGCC plants equipped for CCS emit an even smaller amount of CO_2 than uncontrolled natural gas-fired units (and therefore pay only a small tax). However, at low carbon prices the minor savings in carbon tax due to capturing CO_2 does not justify the large capital outlay required to finance CCS retrofits. Therefore, NGCC plants are not motivated to install any level of CCS if the carbon price is below the plant's avoided cost of 90% CO_2 capture. It should be noted that this result is specific to the natural gas prices assumed for this analysis (which were representative of fuel prices paid by existing NGCC units in these regions for 2009). As fuel prices change, the CO_2 tax that motivates CCS retrofits will vary as well.

---

[1] First-year COE is the 30-year LCOE, divided by the levelization factor. When discussing plant dispatch and the application of CO_2 taxes, first-year COE is a more relevant metric and is therefore used throughout this analysis.

[2] Carbon taxes throughout are in 2007 dollars, escalating at a nominal rate of 3% per year consistent with the assumed general inflation rate. This analysis assumes a capacity factor of 75% for both the existing NGCC and the NGCC retrofit with CCS and natural gas prices of $4.40/MMBtu and $5.90/MMBtu for the midwest and western locations, respectively.

1.2 EFFECT OF CO_2 TAX ON COMPETITION BETWEEN UNCONTROLLED NGCC AND PULVERIZED COAL RETROFITS IN THE WESTERN U.S.

Although this analysis considers existing NGCC plants situated in both the midwestern and western U.S., much of the discussion that follows focuses strictly on the western plants. Competitive power markets (which determine plant dispatch order based on each plant's marginal cost) such as the California Independent System Operator (CA ISO) are dominated primarily by natural gas-fired units (both NGCC and simple cycle gas peaking units), as shown in Figure 1.

Merit order dispatch determines in what order the generating units are dispatched, based on each plant's marginal cost. Marginal cost is the sum of fuel costs, plus variable operations and maintenance (O&M) costs, expressed in first year dollars (as opposed to LCOE, which is levelized over a 30-year period and reported in current, mixed-year dollars). In competitive markets, those plants with the lowest marginal costs are dispatched first to meet the demand for power at any given time. Units that meet the base load (and therefore have a high capacity factor) in a given area are typically those plants with minimal fuel costs, such as nuclear plants (in the eastern U.S.) or hydroelectric units, when available (in the western U.S.).

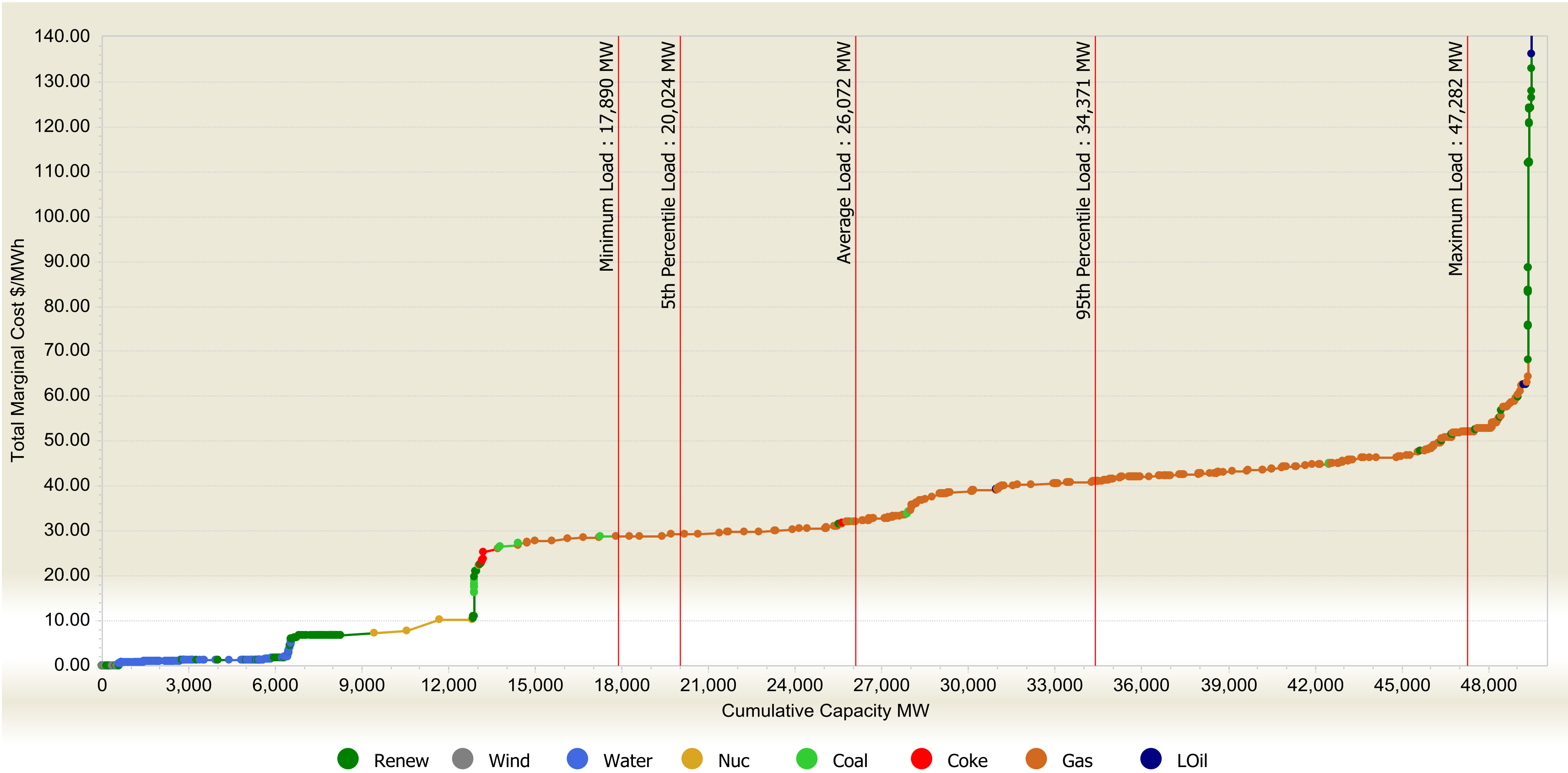
On a merit-order dispatch basis, existing coal units are currently cheaper to operate than gas-fired plants due primarily to the large difference in fuel costs between coal and gas[3]. However, the application of a sufficiently high carbon tax could reverse this trend, making the gas-fired units cheaper than coal-fired, because coal is a more carbon-intensive fuel than gas (and therefore would pay a higher carbon tax than the gas-fired units).

Implementation of a carbon tax may encourage many existing coal-fired units in the western United States to retrofit for CCS in order to stay competitive with natural gas-fired units. By capturing and sequestering CO_2, coal-fired units will keep their marginal costs low by minimizing their carbon tax payments.

---

[3] The natural gas price assumed for the western NGCC retrofit case is \$5.90/MMBtu, representative of the price paid by plants in WECC in 2009. The coal price assumed for the referenced subcritical pulverized coal retrofit is \$1.31/MMBtu.

Figure 1 – CA ISO Dispatch Order[4]



---

[4] This curve represents a ***conceptual*** CA ISO dispatch order as of September 30, 2010. It includes CA ISO, as well as several large coal-fired power plants in AZ, CO, NM, and UT that typically export power into CA. This curve is for illustrative purposes only, and assumes a perfectly efficient power market. It omits issues such as outage, capacity payments, and imperfections that prevent operation of a perfectly efficient market. Total marginal cost (shown on the ordinate in units of $/MWh) is the sum of fuel and variable O&M costs, and is expressed in first-year dollars (as opposed to being levelized).

Figure 2 shows the same theoretical CA ISO dispatch order that was presented in Figure 1, but with the application of a carbon tax of $75/tonne CO_2. In Figure 1, as demand grows (shown on the abscissa) the coal-fired units (bright green markers) dispatch before natural gas-fired. However, Figure 2 shows that when a carbon tax of $75/tonne CO_2 is applied, this trend is reversed: gas-fired units are dispatched first, ahead of coal units, to meet demand. Since all generating units in Figure 2 are now paying a CO_2 tax on their emissions, those units with lower emissions (such as natural gas-fired) have a lower marginal cost than other higher emitting plants (such as coal-fired), at this level of carbon tax.

The previously analyzed pulverized coal (PC)[ii] and the western NGCC retrofit plant modeled in this analysis have also been included in the dispatch curve in Figure 2 (diamond markers), which clearly shows that a retrofitted subcritical PC plant (90% CCS) has a lower marginal cost than a retrofitted NGCC unit (90% CCS), and therefore will dispatch ahead of it. ***Although the COE of the PC retrofit is about 17% higher than an NGCC retrofit, its marginal cost is about a third less. This means that since it is cheaper to operate, in a competitive market, it will dispatch ahead of the NGCC retrofit.*** This comparison between marginal cost and first-year COE is shown in Table 1.

Table 1 – Marginal and First-Year Costs for Western NGCC and Subcritical PC Retrofits[5]

	Marginal Cost, $/MWh[6]	First-Year COE, $/MWh
Subcritical PC Retrofit	42.0	98.3
NGCC Retrofit	61.5	83.6

Although the PC retrofit has a greater first-year COE than the NGCC retrofit, it is important to bear in mind that COE is a measure of the power price a plant needs to receive to satisfy its rate of return requirement. It is not a reflection of which plant is cheaper to operate. The relative cost of operation between two plants is more accurately captured in the marginal cost. In competitive markets, plants with lower marginal costs will dispatch more frequently than those plants with higher marginal costs, and will therefore have higher capacity factors. ***Inspection of Figure 2 reveals that the existing NGCC plant that retrofitted for 90% CO_2 capture hardly improved its dispatch position relative to the other NGCC plants that did not retrofit. The subcritical PC plant that retrofitted for 90% CCS realized a far greater improvement in its dispatch position than the NGCC retrofit. The capacity factor of the PC retrofit would drastically improve as a result.*** Furthermore, applying the capacity factors that would result from a merit order dispatch has the potential to reduce the COE advantage of NGCC retrofits over PC retrofits.

---

[5] All costs in this table include 90% CCS and application of a $75/tonne CO_2 tax.

[6] Marginal costs are expressed in first-year dollars, and represent the sum of fuel, variable O&M, and carbon tax payments.

Figure 2 – CA ISO Dispatch Order with Carbon Tax ($75/tonne CO_2)[7]

[7] This curve represents a *possible* CA ISO dispatch order after application of a carbon tax of $75/tonne CO_2. Although this curve contains actual operating plants, it is for illustrative purposes only.

2. Analysis of COE Results

This section presents a more detailed analysis of the results of this study, which investigates the cost and performance associated with CCS retrofits of existing natural gas combined cycle plants.

2.1 Effect of CO_2 Tax on Levelized Cost of Electricity

The first-year cost of electricity for retrofit cases in both the midwestern, and western U.S., are shown in Figure 3 and Figure 4, respectively. Costs are shown as a function of percent carbon capture. In this study, CO_2 control is done via post-combustion capture with an Econamine scrubber. For reduced levels of CO_2 capture (below 90%), it is assumed that only a portion of the flue gas is treated. This study assumes that a plant will operate only at a single level of capture, and the CO_2 scrubbing unit and flue gas bypass rates are sized and controlled accordingly to achieve the desired level of capture.

The first-year COE's presented in Figure 3 and Figure 4 also include CO_2 tax as a parametric variable. Carbon taxes ranging from \$0 to \$100 per tonne of CO_2 emitted are considered. For both the western and midwestern plants, an additional case is shown where the carbon tax is equal to the avoided cost of 90% CO_2 capture, which is expressed in units of \$/tonne CO_2 and defined by:

$$Avoided\_Cost = \frac{\left(1^{st} YearCOE_{With\_90\%\_CCS} - 1^{st} YearCOE_{Without\_CCS}\right)\frac{\$}{MWh}}{\left(Emissions_{Without\_CCS} - Emissions_{With\_90\%\_CCS}\right)\frac{tonne\_CO_2}{MWh}}$$

By definition, the avoided cost of 90% CO_2 capture is the carbon tax which sets the COE's of the 90% CCS and "no capture" cases equal to one another. This is shown in Figure 3 at \$65.28/tonne CO_2 (which is the avoided cost of 90% capture). The first-year COE's of the no-capture and 90% capture cases are exactly equal to one another when taxed at this rate. Likewise in Figure 4, the first-year COE's of the no-capture and 90% capture cases are equal at a tax of \$72.11/ tonne CO_2, the avoided cost of 90% CCS.

If the CO_2 tax were exactly equal to the avoided cost of 90% CO_2 capture, it makes no difference (from a COE perspective) if the plant captures 90% CO_2, or captures none at all.

2.1.1 CO_2 Tax Below Avoided Cost of 90% Capture

When the CO_2 tax is *below* the avoided cost of 90% capture, a plant's minimum first-year COE occurs when there is no CCS, and the full burden of the CO_2 tax is paid. This trend is shown in Figure 3 and Figure 4, for the taxes (\$0, \$25, and \$50/tonne CO_2) that are less than the avoided cost of 90% capture. Since natural gas has a relatively low carbon intensity, NGCC flue gas contains little CO_2 (relative to coal-derived flue gas). The large capital outlay required for a CCS retrofit is not justified when the tax on the small amount of CO_2 emitted from NGCC plants is so low. Therefore the minimum COE occurs when the plant captures no CO_2, and pays the tax on the full amount of its emissions. ***This analysis therefore concludes that if the tax is less than***

the avoided cost of 90% CO_2 capture (the upper limit considered in this study), there is no economic incentive for a plant to practice carbon capture and sequestration.

2.1.2 CO_2 Tax Above Avoided Cost of 90% Capture

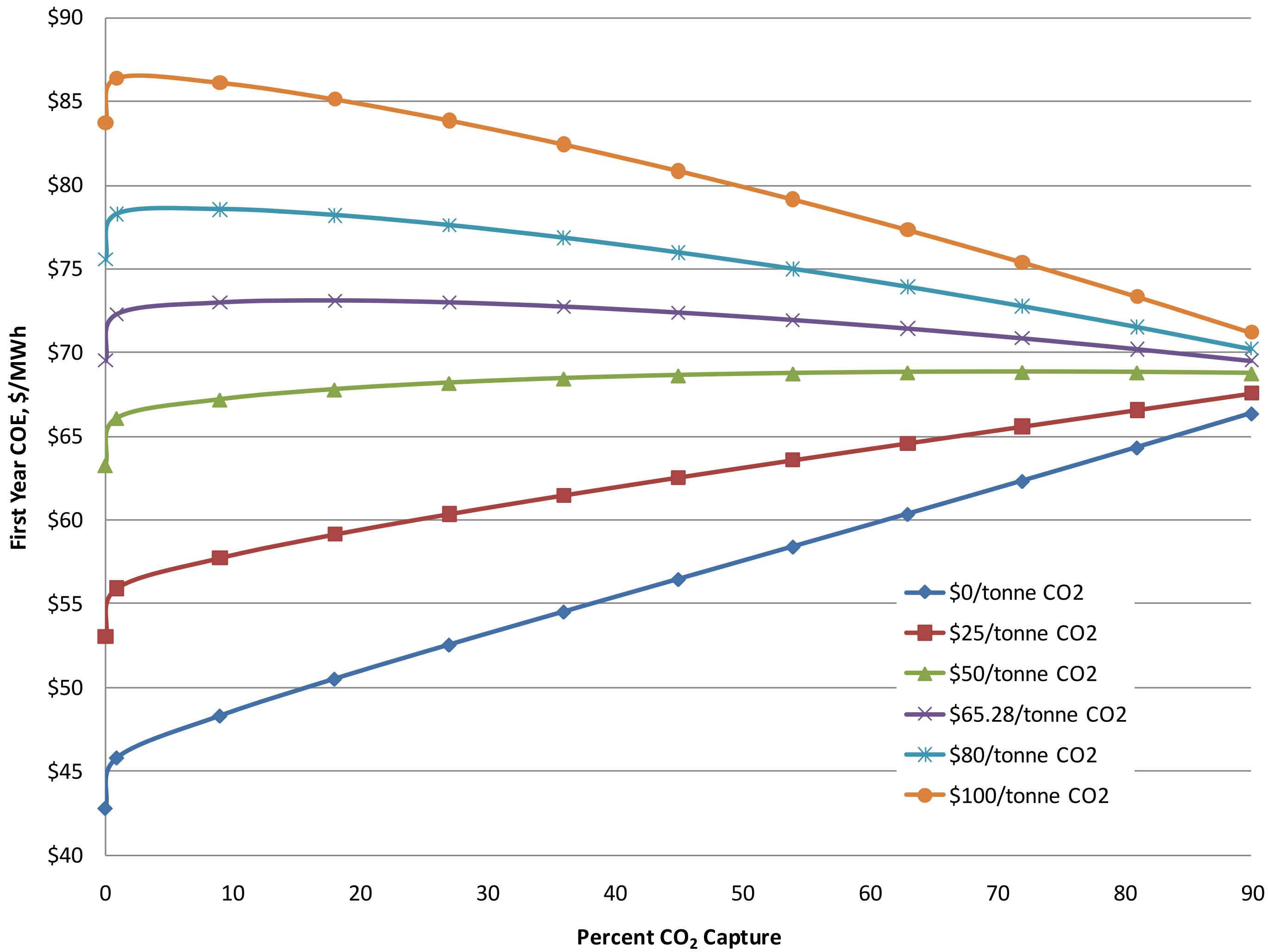
If the CO_2 tax is *above* the avoided cost of 90% capture, the NGCC units in this study minimize first-year COE by capturing as much CO_2 as possible (90% in this analysis). This is shown in Figure 3 and Figure 4 at taxes of $80 and $100/tonne CO_2. The minimum COE is when the maximum amount of CO_2 is captured. When the tax is above the avoided cost of 90% capture, it becomes so expensive to emit CO_2 that the large capital outlay required to finance CCS retrofits is justified.

For taxes above the avoided cost of 90% capture, there is no economic justification (from a first-year COE perspective) for any degree of CO_2 capture less than the maximum amount. First-year COE increases as soon as CCS equipment is installed. This is shown by the increase from 0% CCS to approximately 1% CCS in Figure 3 and Figure 4. For lesser rates of CO_2 capture, COE actually increases above the no-capture (0% CCS) case. This concept is illustrated by considering the $80/tonne CO_2 case in Figure 3.

Without CCS, first-year COE is $75/MWh at this tax rate. The moment the plant is retrofitted for CCS, COE increases to approximately $78/MWh, and stays well above the “no capture” COE until approximately 55% CCS. Beyond 55% capture, the COE starts to fall below the “no capture” case, and an economic benefit of retrofitting is realized.

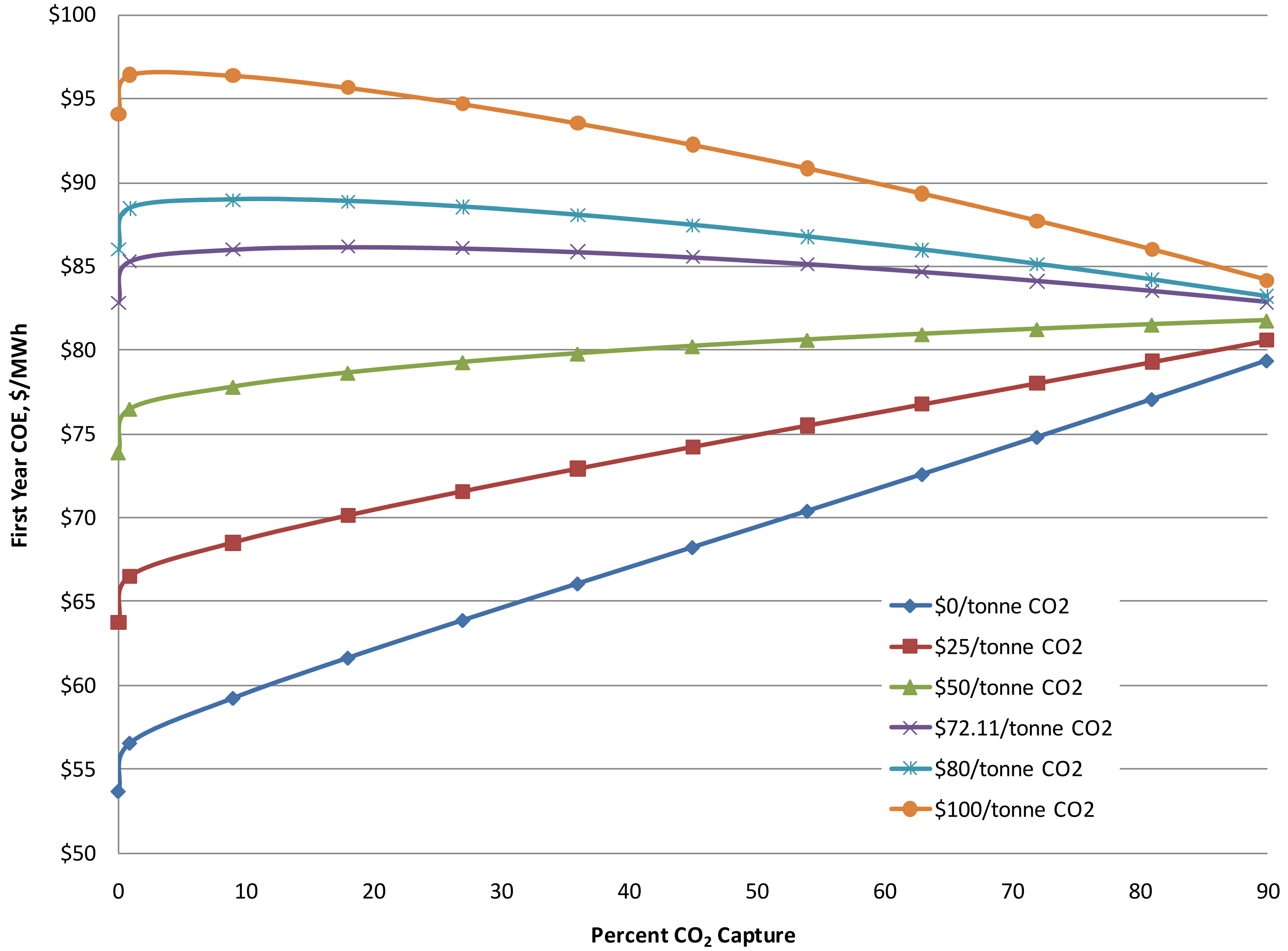
While the specific costs, taxes and capture rates will vary depending on the assumptions made, this result will be true for all taxes above the avoided cost of 90% CO_2 capture. ***This analysis therefore finds that when the CO_2 tax is above the avoided cost of 90% capture (the upper limit considered in this study), the minimum COE will be when the NGCC retrofit unit captures the maximum amount of carbon dioxide. Further, it makes no economic sense (from a first-year COE perspective) to capture any amount of CO_2 less than the maximum possible.***

Figure 3 – Midwestern NGCC First Year COE as a Function of Percent Carbon Capture[8]



[8] The natural gas price is assumed to be $4.40/MMBtu, which is typical of the price paid by existing NGCC plants in PJM in 2009.

Figure 4 – Western NGCC First Year COE as a Function of Percent Carbon Capture[9]



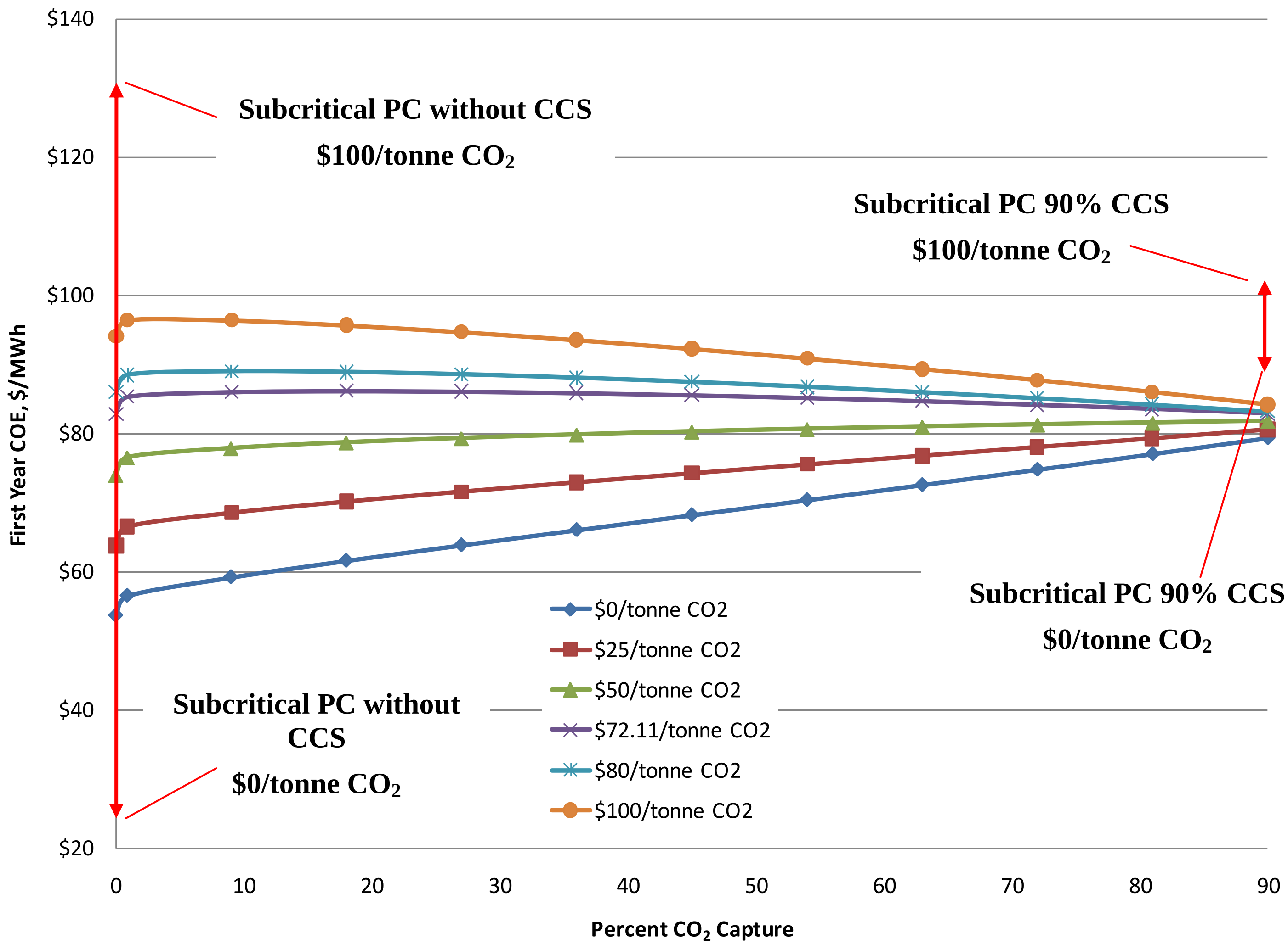
[9] The natural gas price is assumed to be $5.90/MMBtu, which is typical of the price paid by existing NGCC plants in WECC in 2009.

Figure 5 shows the first-year COE of an existing, western U.S. NGCC with carbon capture, and compares it to the first-year COE of an existing western subcritical pulverized coal (PC) plant with 0% and 90% CCS[ii].

With no CCS or CO_2 tax, an existing PC plant has a lower first-year COE than an existing NGCC plant. This is due primarily to the more expensive fuel used in an NGCC plant ($5.90/MMBtu for natural gas in the western NGCC case, compared to $1.31/MMBtu assumed for coal in that particular study[ii]). However as a carbon tax is applied, the COE of the existing PC plant quickly exceeds that of an existing NGCC (assuming no CCS). This is due to the higher carbon intensity of coal relative to natural gas. Since the PC plant emits more CO_2 than an equivalent NGCC plant, the carbon tax paid will significantly increase total COE for scenarios where there is no CCS (the carbon intensity of coal is approximately 2.1 lb CO_2/kWh generated; for natural gas, the same metric is approximately 1.3 lb CO_2/kWh generated[i]). For instance, in Figure 5, the portion of COE that is attributable to the carbon tax for the NGCC plant without CCS is 43% at $100/tonne CO_2. For comparison, without CCS, an existing subcritical PC plant owes approximately 80% of its total COE to the carbon tax at $100/tonne CO_2.

With 90% CCS, the COE gap between PC and NGCC plants is greatly reduced relative to the no-capture cases. However, for the fuel prices considered in this study, NGCC retrofits with 90% CCS still have a slightly lower first-year COE than PC retrofits with 90% CCS.

Figure 5 – Western NGCC First Year COE as a Function of Percent Carbon Capture[10]



[10] The natural gas price is assumed to be $5.90/MMBtu, which is typical of the price paid by existing NGCC plants in WECC in 2009.

2.2 Effect of Natural Gas Price on First-Year Cost of Electricity

The effect of natural gas price on western NGCC retrofit COE over a range of carbon taxes (at a constant CO_2 capture level of 90%) is shown in Figure 6. For comparison, the first-year COE's for western U.S. subcritical PC retrofits with 90% CCS at three carbon tax values ($0, $50, and $100/tonne CO_2) are also shown.

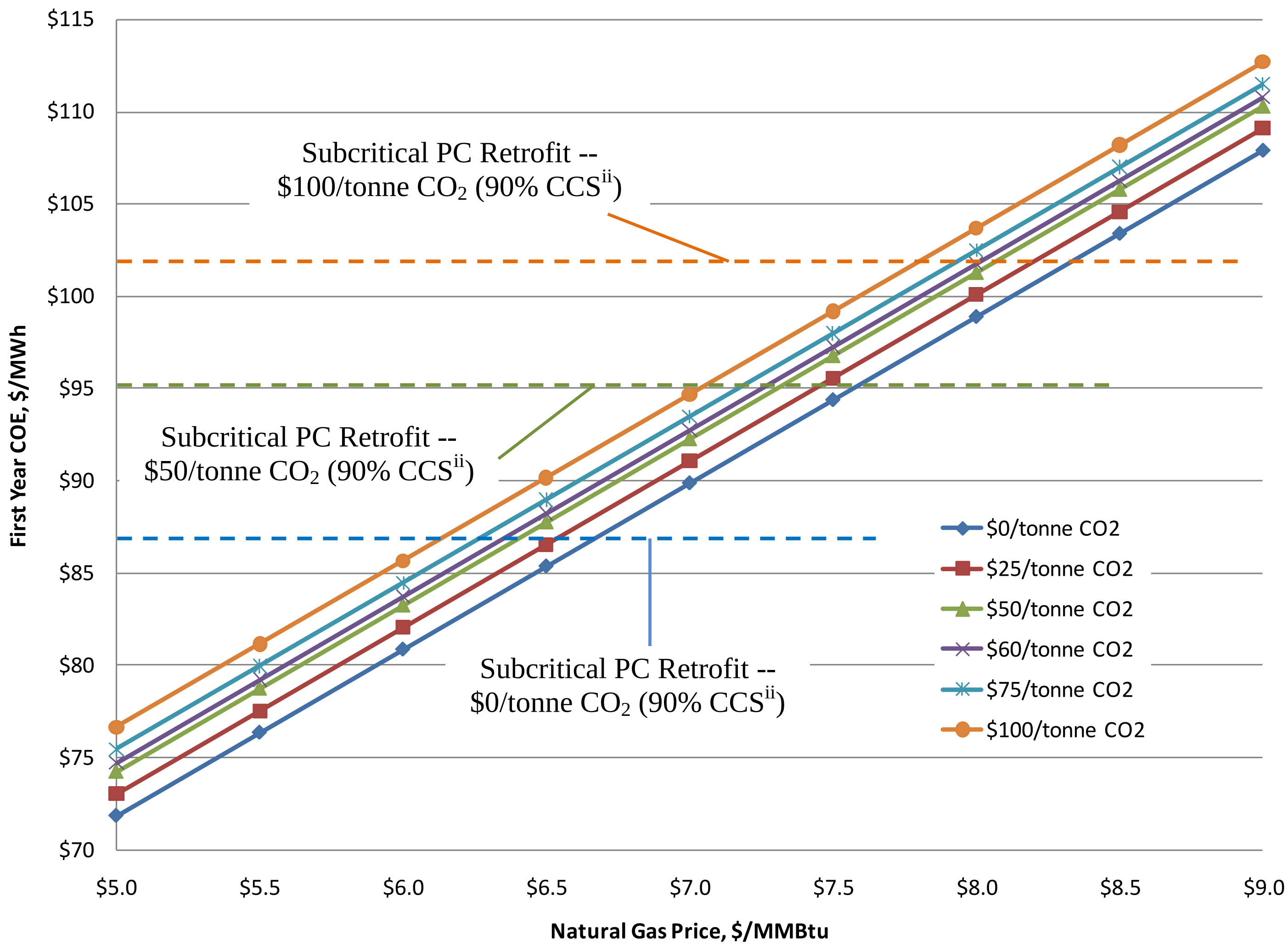
Figure 6 indicates that at the natural gas price assumed for the western NGCC cases in this study ($5.90/MMBtu), PC retrofits are not cost-competitive (on a COE basis) with NGCC retrofits at any level of carbon tax. At a carbon price of $50/tonne CO_2, subcritical PC retrofits become competitive with NGCC retrofits at a natural gas price of approximately $7.25/MMBtu. Likewise, at a carbon price of $100/tonne CO_2, subcritical PC retrofits become competitive with NGCC retrofits at a natural gas price of approximately $8.00/MMBtu. ***The trend that can be inferred from Figure 6 is that the COE disparity between subcritical PC retrofits and NGCC retrofits diminishes as natural gas price increases.***

Figure 3 and Figure 4 above show that if the carbon price is below the avoided cost of 90% CO_2 capture, there is no economic incentive for NGCC plants to retrofit for CCS. At low carbon prices, the small amount of CO_2 that is emitted from NGCC units does not justify the large capital outlay required to finance retrofit projects. Therefore, Figure 7 shows the first-year COE for existing *uncontrolled* NGCC units, compared to existing subcritical PC units that retrofit for 90% CCS, over a carbon tax ranging from $0 to $60/tonne CO_2.

For a carbon tax of $25/tonne CO_2, subcritical PC units with 90% CCS only become cost-competitive with uncontrolled NGCC units when the natural gas price is in excess of $9.00/MMBtu. When the carbon price reaches $60/tonne CO_2, the subcritical PC retrofit units become competitive with uncontrolled NGCC sooner: at a natural gas price of about $8.25/MMBtu. ***Figure 7 demonstrates that for low carbon tax values ($0 to $60 per tonne CO_2), existing uncontrolled NGCC units can still be less costly than subcritical PC retrofits that capture to 90% (on a first-year COE basis). However, this cost benefit begins to diminish as either natural gas price, or CO_2 price, increases.***

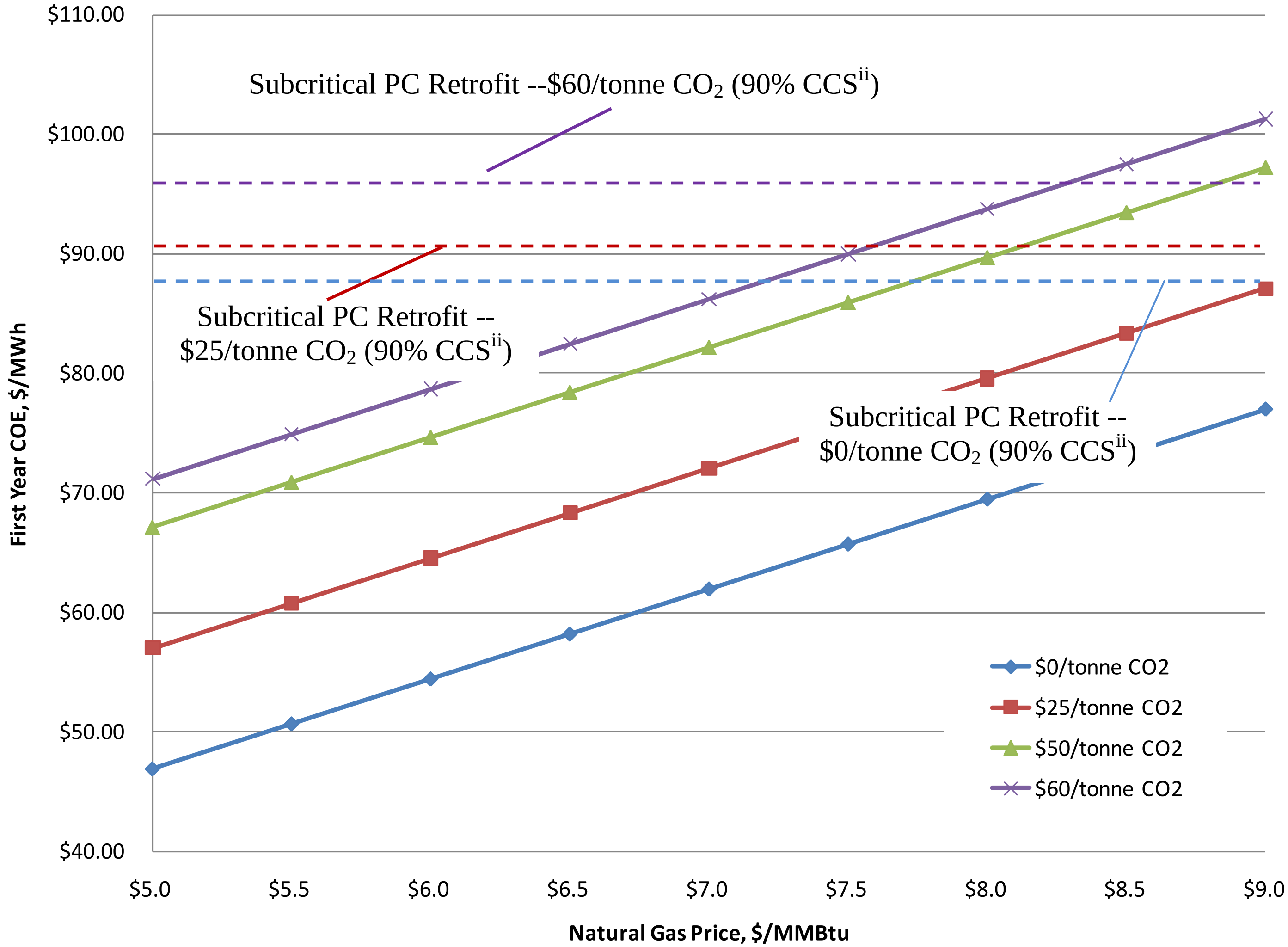
It is emphasized that at the natural gas price assumed for the western U.S. cases in this study, NGCC units (either controlled or uncontrolled) appear to have a clear cost advantage over existing PC units. However a "dash to gas" scenario which may occur as a result of climate change legislation will likely apply upward pressure to natural gas prices due to increased demand, and this cost advantage will begin to disappear. Once price equilibrium is reached, the degree of NGCC's advantage will depend largely on how high natural gas prices have risen.

Figure 6 – Western NGCC (with 90% CCS) First Year COE as a Function of Natural Gas Price[11]



[11] All values in this figure assume 90% carbon capture.

Figure 7 – Uncontrolled Western NGCC First Year COE as a Function of Natural Gas Price[12]



12 All NGCC costs in Figure 7 assume no CCS.

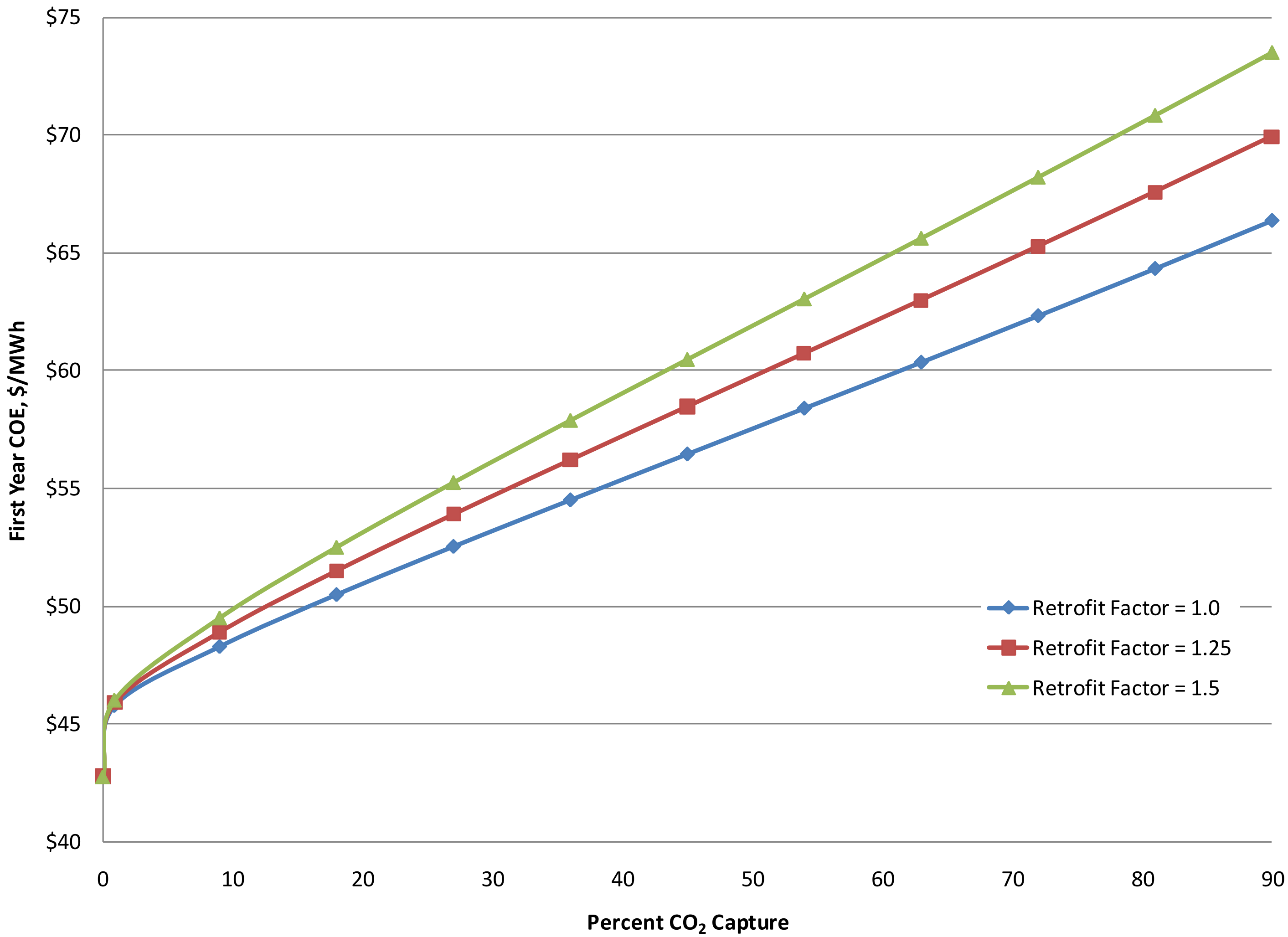
2.3 Retrofit Uncertainty and Effect on First-Year Cost of Electricity

The true cost of a CCS retrofit will likely vary from project to project. Greenfield plant designs have the benefit of working with sites that are open in terms of space, and lack of obstructions. CCS retrofit projects will have the extra element of difficulty of being forced to work within the confines of what are usually already cramped sites. This includes design issues such as having to work around existing structures (buildings and pipe racks), site access limitations (which can make project mobilization/demobilization difficult), having to work with existing site utility infrastructure (such as water purity issues and resource availability), and many others. Working through these types of difficulties will add extra cost to any CCS retrofit project, but these costs are difficult to quantify and will likely vary from project to project.

This analysis evaluates the effect of a retrofit factor on the first-year cost of electricity. The retrofit factor is a multiplier that is applied to the total plant cost (TPC) that accounts for difficulties such as those described above. In this example, the retrofit factor assumed varies between 1.0 (which assumes no added difficulty for retrofits) and 1.5 (which would be a 50% adder to TPC).

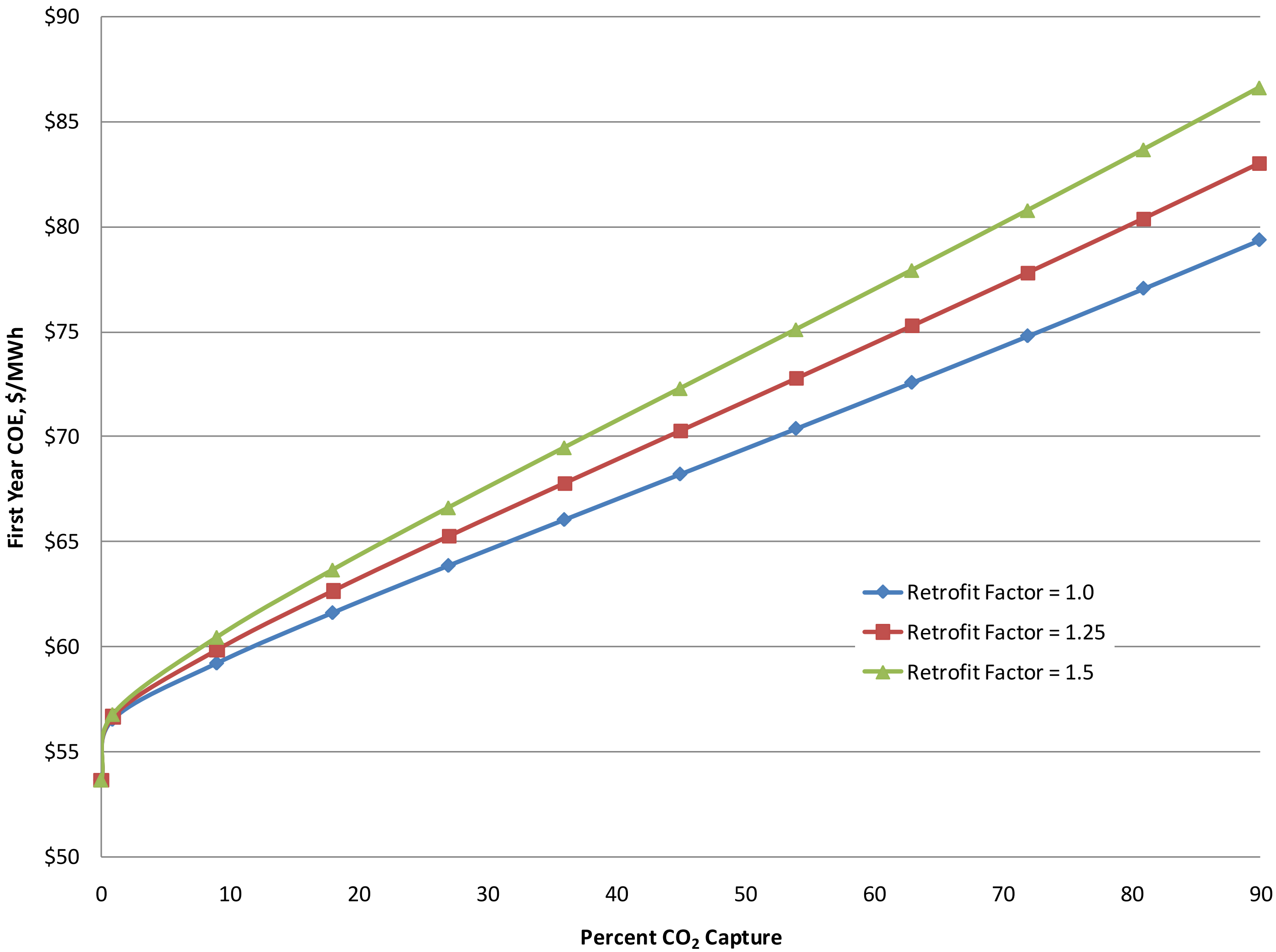
The effect of applying a retrofit factor on first-year COE is shown in Figure 8 and Figure 9. For the midwestern and western U.S. cases, a 50% cost adder to TPC (retrofit factor of 1.5) results in about a 10% first-year COE increase at 90% CCS.

Figure 8 – Effect of Retrofit Factor on First-Year COE for Midwestern NGCC Retrofits[13]



[13] A natural gas price of $4.40/MMBtu is assumed, and no carbon tax is applied.

Figure 9 – Effect of Retrofit Factor on First-Year COE for Western U.S. NGCC Retrofits[14]



[14] A natural gas price of $5.90/MMBtu is assumed, and no carbon tax is applied.

2.4 Avoided Cost of CO_2 Capture

The avoided cost of CO_2 capture is expressed in this analysis in units of $/tonne CO_2, and is defined by the following equation:

$$Avoided\_Cost = \frac{\left(1^{st}\,YearCOE_{With\_CCS} - 1^{st}\,YearCOE_{Without\_CCS}\right)\frac{\$}{MWh}}{\left(Emissions_{Without\_CCS} - Emissions_{With\_CCS}\right)\frac{tonne\_CO_2}{MWh}}$$

A unique avoided cost of capture can be calculated for each degree of CCS considered in this analysis. The avoided costs for the midwestern and western NGCC retrofit cases are shown in Table 2 and Table 3, respectively.

If an NGCC unit with CCS is taxed on emissions at a rate equal to the avoided cost of capture at that particular level of removal, the resulting COE will be exactly equal to the no-capture case also taxed at that same level. This is shown in the two columns on the far right in Table 2 and Table 3.

Avoided cost is a useful metric for determining the carbon tax at which the COE's for the "capture" and "no capture" cases are equal (at a specific level of CCS). Frequently, avoided cost is viewed as the carbon tax that would motivate CO_2 capture (at a tax above the avoided cost, COE decreases with CCS, so a plant would minimize their COE by capturing; when the CO_2 tax is below avoided cost, COE increases with CCS, so a plant would be better served not capturing, and paying the full tax).

Table 2 – Avoided Cost Summary for Midwestern NGCC Retrofit Cases[15]

Percent CO_2 Capture	First-Year COE, NGCC with CCS, \$/MWh (No CO_2 Tax)	CO_2 Emissions, tonne CO_2/MWh	First-Year Avoided Cost, \$/tonne CO_2 avoided	First-Year COE, NGCC with CCS, CO_2 Tax = Avoided Cost	First-Year COE, NGCC without CCS, CO_2 Tax = Avoided Cost
0	-	0.410	-	-	-
1	45.78	0.406	816.57	377.54	377.54
9	48.29	0.378	174.84	114.44	114.44
18	50.49	0.346	121.62	92.62	92.62
27	52.53	0.313	101.21	84.25	84.25
36	54.50	0.279	89.91	79.62	79.62
45	56.45	0.244	82.55	76.60	76.60
54	58.39	0.208	77.27	74.44	74.44
63	60.34	0.170	73.26	72.80	72.80
72	62.32	0.131	70.08	71.49	71.49
81	64.32	0.090	67.47	70.42	70.42
90	66.36	0.048	65.28	69.52	69.52

[15] The first-year COE for an existing NGCC plant without CO_2 capture, and without application of a carbon tax, is \$42.76/MWh.

Table 3 – Avoided Cost Summary for Western NGCC Retrofit Cases[16]

Percent CO_2 Capture	First-Year COE, NGCC with CCS, \$/MWh (No CO_2 Tax)	CO_2 Emissions, tonne CO_2/MWh	First-Year Avoided Cost, \$/tonne CO_2 avoided	First-Year COE, NGCC with CCS, CO_2 Tax = Avoided Cost	First-Year COE, NGCC without CCS, CO_2 Tax = Avoided Cost
0	-	0.405	-	-	-
1	56.53	0.400	508.44	259.55	259.55
9	59.21	0.372	168.89	122.04	122.04
18	61.62	0.341	124.09	103.90	103.90
27	63.87	0.308	105.85	96.51	96.51
36	66.06	0.275	95.47	92.31	92.31
45	68.23	0.240	88.60	89.52	89.52
54	70.40	0.205	83.62	87.50	87.50
63	72.59	0.167	79.80	85.96	85.96
72	74.82	0.129	76.74	84.72	84.72
81	77.08	0.089	74.23	83.70	83.70
90	79.39	0.048	72.11	82.84	82.84

[16] The first-year COE for an existing NGCC plant without CO_2 capture, and without application of a carbon tax, is \$53.64/MWh.

3. General Evaluation Basis

For each of the plant configurations in this study an AspenPlus model was developed and used to generate material and energy balances. Performance and process limits were based upon published reports, information obtained from vendors and users of the technology, performance data from design/build utility projects, and/or best engineering judgment.

3.1 Site Characteristics

All plants in this study are assumed to be located at one of two locations: a generic plant site in midwestern USA, or a site representative of the western USA. Ambient conditions and site characteristics are presented in Table 4 and Table 5, respectively.

Table 4 – Midwestern Site Ambient Conditions

Elevation, ft	0
Barometric Pressure, psia	14.696
Design Ambient Temperature, Dry Bulb, °F	59
Design Ambient Temperature, Wet Bulb, °F	51.5
Design Ambient Relative Humidity, %	60

Table 5– Western Site Ambient Conditions

Elevation, ft	3,400
Barometric Pressure, psia	13.0
Design Ambient Temperature, Dry Bulb, °F	42
Design Ambient Temperature, Wet Bulb, °F	37
Design Ambient Relative Humidity, %	62

Table 6 - Site Characteristics

Location	Midwestern USA	Western USA
Topography	Level	Level
Size, acres	300	300
Transportation	Rail	Rail
Ash/Slag Disposal	Off Site	Off Site
Water	Municipal (50%) / Groundwater (50%)	Municipal (50%) / Groundwater (50%)
Access	Land locked, having access by rail and highway	Land locked, having access by rail and highway
CO_2 Storage	Compressed to 15.3 MPa (2,215 psia), transported 80 kilometers (km) (50 miles), and sequestered in a saline formation at a depth of 1,239 m (4,055 ft)	Compressed to 15.3 MPa (2,215 psia), transported 80 kilometers (km) (50 miles), and sequestered in a saline formation at a depth of 1,239 m (4,055 ft)

The following design parameters are considered site-specific, and are not quantified for this study. Flood plain considerations

- Flood plain considerations
- Existing soil/site conditions
- Water discharges and reuse
- Rainfall/snowfall criteria
- Seismic design
- Buildings/enclosures
- Fire protection
- Local code height requirements
- Noise regulations – Impact on site and surrounding area

3.2 Natural Gas Characteristics

Natural gas is utilized as the main fuel, and its composition is presented in Table 7.

Table 7 - Natural Gas Composition

Component		Volume Percentage
Methane	CH_4	93.1
Ethane	C_2H_6	3.2
Propane	C_3H_8	0.7
n-Butane	C_4H_{10}	0.4
Carbon Dioxide	CO_2	1.0
Nitrogen	N_2	1.6
	Total	100.0

	LHV	HHV
kJ/kg	47,454	52,581
MJ/scm	34.71	38.46
Btu/lb	20,410	22,549
Btu/scf	932	1,032

The first-year cost of natural gas used in this study is $5.90/MMBtu for western plants (average fuel gas price paid by existing NGCC units in the Western Electricity Coordinating Council (WECC) region in 2009), and $4.40/MMBtu for midwestern plants (average fuel gas price paid by existing NGCC units in the PJM ISO in 2009).

3.3 COST ESTIMATING METHODOLOGY

The TPC and O&M costs for each of the cases in the study were factored cost estimates from recent NETL studies. The costs in those studies were estimated by WorleyParsons Group Inc. (WorleyParsons). The estimates carry an accuracy of ±30 percent, consistent with the screening study level of information available for the various power technologies.

WorleyParsons used an in-house database and conceptual estimating models for the capital cost and O&M cost estimates. Costs were further calibrated using a combination of adjusted vendor-furnished and actual cost data from recent design and design/build projects.

The capital costs for each cost account were reviewed by comparing individual accounts across all cases to ensure an accurate representation of the relative cost differences between the cases and accounts.

All capital costs are presented as "overnight costs" expressed in June 2007 dollars. The capital expenditure period is 3 years for all NGCC cases.

Capital costs are presented at the TPC level. TPC includes:

- Equipment (complete with initial chemical and catalyst loadings),
- Materials,
- Labor (direct and indirect),

- Engineering and construction management, and
- Contingencies (process and project).

Owner's costs were subsequently calculated and added to the TPC, the result of which is the TOC. Additionally, financing costs were estimated and added to TOC to provide TASC. The current-dollar, 30-year LCOE was calculated using TOC. First-year COE is determined by dividing the 30-year LCOE by the appropriate levelization factor.

System Code-of-Accounts
The costs are grouped according to a process/system oriented code of accounts. This type of code-of-account structure has the advantage of grouping all reasonably allocable components of a system or process, so they are included within the specific system account.

CO_2 Removal Plant Maturity
While the post-combustion CO_2 capture technology for NGCC plants has been practiced at smaller scale, it has never been practiced at a scale equivalent to that required in this study. There are domestic amine-based CO_2 capture systems operating on coal-derived flue gas at scales ranging from 150-800 tons per day (TPD)[iii]. The plants in this study will capture an amount greater than that. Consequently the CO_2 capture cases will be treated as FOAK.

Contracting Strategy
The estimates are based on an EPCM approach utilizing multiple subcontracts. This approach provides the Owner with greater control of the project, while minimizing, if not eliminating most of the risk premiums typically included in an engineer/procure/construct (EPC) contract price.

In a traditional lump sum EPC contract, the Contractor assumes all risk for performance, schedule, and cost. As a result of current market conditions, EPC contractors appear more reluctant to assume that overall level of risk. The current trend appears to be a modified EPC approach where much of the risk remains with the Owner. Where Contractors are willing to accept the risk in EPC type lump-sum arrangements, it is reflected in the project cost. In today's market, Contractor premiums for accepting these risks, particularly performance risk, can be substantial and increase the overall project costs dramatically.

The EPCM approach used as the basis for the estimates here is anticipated to be the most cost effective approach for the Owner. While the Owner retains the risks and absorbs higher project management costs, the risks become reduced with time, as there is better scope definition at the time of contract award(s).

Capital Costs

Key estimate considerations include the following:

- Labor costs are based on Midwest, Merit Shop using factors from PAS, Inc[iv]. PAS presents information for eight separate regions. Costs would need to be re-evaluated for projects employing union labor.
- The estimates are based on a competitive bidding environment, with adequate skilled craft labor available locally.

- Labor is based on a 50-hour work-week (5-10s). No additional incentives such as per-diems or bonuses have been included to attract craft labor.
- While not included at this time, labor incentives may ultimately be required to attract and retain skilled labor depending on the amount of competing work in the region, and the availability of skilled craft in the area at the time the projects proceed to construction. Current indications are that regional craft shortages are likely over the next several years. The types and amounts of incentives will vary based on project location and timing relative to other work. The cost impact resulting from an inadequate local work force can be significant.
- The site is considered to be Seismic Zone 1, relatively level, and free from hazardous materials, archeological artifacts, or excessive rock. Soil conditions are considered adequate for spread footing foundations. The soil bearing capability is assumed adequate such that piling is not needed to support the foundation loads.
- Costs are limited to within the "fence line," terminating at the high voltage side of the main power transformers with the exception of costs included for TS&M of CO_2 in all capture cases.
- Engineering and Construction Management were estimated as a percent of BEC. These costs consist of all home office engineering and procurement services as well as field construction management costs. Site staffing generally includes a construction manager, resident engineer, scheduler, and personnel for project controls, document control, materials management, site safety, and field inspection.
- All capital costs are presented as "Overnight Costs" in June 2007 dollars. Escalation to period-of-performance is specifically excluded.

Price Escalation

A significant change in power plant cost occurred in recent years due to the significant increases in the pricing of equipment and bulk materials. This estimate includes these increases. All vendor quotes used to develop these estimates were received within the last three years. The price escalation of vendor quotes incorporated a vendor survey of actual and projected pricing increases from 2004 through mid-2007 that WorleyParsons conducted for a recent project. The results of that survey were used to validate/recalibrate the corresponding escalation factors used in the conceptual estimating models.

Cross-comparisons

In all technology comparison studies, the relative differences in costs are often more important than the absolute level of TOC. This requires cross-account comparison between technologies to review the consistency of the direction of the costs. As noted above, the capital costs were reviewed and compared across all cases to ensure that a consistent representation of the relative cost differences is reflected in the estimates.

When performing such a comparison, it is important to reference the technical parameters for each specific item, as these are the basis for establishing the costs. Scope or assumption differences can quickly explain any apparent anomalies.

Exclusions
The capital cost estimate includes all anticipated costs for equipment and materials, installation labor, professional services (Engineering and Construction Management), owner's costs, and contingency. The following items are extremely project and site specific and are therefore excluded from the capital costs:

- Site specific considerations – including, but not limited to seismic zone, accessibility, local regulatory requirements, water supply line, wastewater discharge line, transmission lines, excessive rock, piles, laydown space, etc.
- Labor incentives in excess of 5-10s
- Additional premiums associated with an EPC contracting approach

Contingency
Both the project contingency and process contingency costs represent costs that are expected to be spent in the development and execution of the project that are not yet fully reflected in the design. It is industry practice to include project contingency in the TPC to cover project uncertainty and the cost of any additional equipment that would result during detailed design. Likewise, the estimates include process contingency to cover the cost of any additional equipment that would be required as a result of continued technology development.

<u>Project Contingency</u>
Project contingencies were added to each of the capital accounts to cover project uncertainty and the cost of any additional equipment that could result from detailed design. The project contingencies represent costs that are expected to occur. Each BEC account was evaluated against the level of estimate detail, field experience, and the basis for the equipment pricing to define project contingency.

The capital cost estimates associated with the plant designs in this study were derived from various sources which include prior conceptual designs and actual design and construction of both process and power plants.

The Association for the Advancement of Cost Engineering (AACE) International recognizes five classes of estimates. On the surface, the level of project definition of the cases evaluated in this study would appear to fall under an AACE International Class 5 Estimate, associated with less than two percent project definition, and based on preliminary design methodology. However, the study cases are actually more in line with the AACE International Class 4 Estimate, which is associated with equipment factoring, parametric modeling, historical relationship factors, and broad unit cost data.

Based on the AACE International contingency guidelines as presented in NETL's "Quality Guidelines for Energy System Studies" it would appear that the overall project contingencies for the subject cases should be in the range of 30 to 40 percent[v]. However, such contingencies are believed to be too high when the basis for the cost numbers is considered. The costs have been extrapolated from an extensive data base of project costs (estimated, quoted, and actual), based on both conceptual and detailed designs for the various technologies. This information has been used to calibrate the costs in the current studies, thus improving the quality of the overall estimates. As such, the overall project contingencies should be more in the range of 15 to 20 percent with the capture cases being higher than the non-capture cases.

Process Contingency

Process contingency is intended to compensate for uncertainties arising as a result of the state of technology development. Process contingencies have been applied to the estimates as follows:

- CO_2 Removal System (Econamine) – 20 percent on all capture cases - unproven technology at commercial scale in NGCC service.
- Instrumentation and Controls – five percent on all accounts for carbon capture cases.

AACE International provides standards for process contingency relative to technology status; from commercial technology at zero to five percent to new technology with little or no test data at 40 percent. The process contingencies as applied in this study are consistent with the AACE International standards[vi].

All contingencies included in the TPC, both project and process, represent costs that are expected to be spent in the development and execution of the project.

Operations and Maintenance (O&M)

The production costs or operating costs and related maintenance expenses (O&M) pertain to those charges associated with operating and maintaining the power plants over their expected life. These costs include:

- Operating labor
- Maintenance – material and labor
- Administrative and support labor
- Consumables
- Fuel
- Waste disposal
- Co-product or by-product credit (that is, a negative cost for any by-products sold)

There are two components of O&M costs; fixed O&M, which is independent of power generation, and variable O&M, which is proportional to power generation.

Operating Labor

Operating labor cost was determined based on the number of operators required for each specific case. The average base labor rate used to determine annual cost is $34.65/hour (hr). The associated labor burden is estimated at 30 percent of the base labor rate.

Maintenance Material and Labor

Maintenance cost was evaluated on the basis of relationships of maintenance cost to initial capital cost. This represents a weighted analysis in which the individual cost relationships were considered for each major plant component or section.

Administrative and Support Labor

Labor administration and overhead charges are assessed at a rate of 25 percent of the burdened O&M labor.

Consumables

The cost of consumables, including fuel, was determined on the basis of individual rates of consumption, the unit cost of each specific consumable commodity, and the plant annual operating hours.

Quantities for major consumables such as fuel were taken from technology-specific heat and mass balance diagrams developed for each plant application. Other consumables were evaluated on the basis of the quantity required using reference data.

The quantities for initial fills and daily consumables were calculated on a 100 percent operating capacity basis. The annual cost for the daily consumables was then adjusted to incorporate the annual plant operating basis, or CF.

Initial fills of the consumables, fuels and chemicals, are different from the initial chemical loadings (such as reactor catalyst), which are included with the equipment pricing in the capital cost.

Owner's Costs

The owner's costs included in the TOC cost estimate are shown in Table 8.

Table 8 - Owner's Costs Included in TOC

Owner's Cost	Comprising
Preproduction Costs	• 6 months O&M, and administrative & support labor • 1 month maintenance materials • 1 month non-fuel consumables • 1 month of waste disposal costs • 25% of one month's fuel cost @ 100% CF • 2% of TPC
Inventory Capital	• 60 day supply of consumables @ 100% CF • 0.5% of TPC (spare parts)
Land	• $3,000/acre (100 acres for greenfield NGCC)
Financing Costs	• 2.7% of TPC
Other Owner's Costs	• 15% of TPC
Initial Cost for Catalyst and Chemicals	• All initial fills not included in BEC
Prepaid Royalties	• Not included in owner's costs (included with BEC)
Property Taxes & Insurance	• 2% of TPC (Fixed O&M cost)
AFUDC and Escalation	• Varies based on levelization period and financing scenario

Owner's Cost	Comprising
	• 33-yr IOU high risk: TASC = TOC * 1.078 • 33-yr IOU low risk: TASC = TOC * 1.075

The category labeled "Other Owner's Costs" includes the following:

- Preliminary feasibility studies, including a Front-End Engineering Design (FEED) study
- Economic development (costs for incentivizing local collaboration and support)
- Construction and/or improvement of roads and/or railroad spurs outside of site boundary
- Legal fees
- Permitting costs
- Owner's engineering (staff paid by owner to give third-party advice and to help the owner oversee/evaluate the work of the EPC contractor and other contractors)
- Owner's contingency: sometimes called "management reserve," these are funds to cover costs relating to delayed startup, fluctuations in equipment costs, unplanned labor incentives in excess of a 5-10s work week

Cost items excluded from "Other Owner's Costs" include:

- EPC Risk Premiums: Costs estimates are based on an EPCM approach utilizing multiple subcontracts, in which the owner assumes project risks for performance, schedule and cost. This approach provides the owner with greater control of the project, while minimizing, if not eliminating most of the risk premiums typically included in a lump-sum, "turnkey" EPC contract, under which the EPC contractor assumes some or all of the project risks. The EPCM approach used as the basis for the estimates here is anticipated to be the most cost effective approach for the owner.
- Transmission interconnection: the cost of interconnecting with power transmission infrastructure beyond the plant busbar.
- Taxes on capital costs: all capital costs are assumed to be exempt from state and local taxes.
- Unusual site improvements: normal costs associated with improvements to the plant site are included in the BEC, assuming that the site is level and requires no environmental remediation. Unusual costs associated with the following design parameters are excluded: flood plain considerations, existing soil/site conditions, water discharges and reuse, rainfall/snowfall criteria, seismic design, buildings/enclosures, fire protection, local code height requirements, and noise regulations.

CO_2 Transport, Storage and Monitoring

For those cases that feature CO_2 capture, the capital and operating costs for CO_2 TS&M were independently estimated by NETL. Those costs were converted to a LCOE and combined with the plant capital and operating costs to produce an overall LCOE. The TS&M costs were levelized over a 30-year period using the methodology described in the next subsection of this report.

CO_2 TS&M was modeled based on the following assumptions:

- CO_2 is supplied to the pipeline at the plant fence line at a pressure of 15.3 MPa (2,215 psia). The CO_2 product gas composition varies in the cases presented, but is expected to meet the specification described in Table 9.

Table 9 - CO_2 Pipeline Specification

Parameter	Units	Parameter Value
Inlet Pressure	MPa (psia)	15.3 (2,215)
Outlet Pressure	MPa (psia)	10.4 (1,515)
Inlet Temperature	°C (°F)	35 (95)
N_2 Concentration	ppmv	< 300
O_2 Concentration	ppmv	< 40
Ar Concentration	ppmv	< 10

- The CO_2 is transported 80 km (50 miles) via pipeline to a geologic sequestration field for injection into a saline formation.
- The CO_2 is transported and injected as a supercritical fluid in order to avoid two-phase flow and achieve maximum efficiency[vii]. The pipeline is assumed to have an outlet pressure of 10.4 MPa (1,515 psia)–above the supercritical pressure–with no recompression along the way. Accordingly, CO_2 flow in the pipeline was modeled to determine the pipe diameter that results in a pressure drop of 4.8 MPa (700 psi) over an 80 km (50 mile) pipeline length[viii]. (Although not explored in this study, the use of boost compressors and a smaller pipeline diameter could possibly reduce capital costs for sufficiently long pipelines.) The diameter of the injection pipe will be of sufficient size that frictional losses during injection are minimal and no booster compression is required at the well-head in order to achieve an appropriate down-hole pressure.
- The saline formation is at a depth of 1,236 m (4,055 ft) and has a permeability of 22 millidarcy (md) (22 μm^2) and formation pressure of 8.4 MPa (1,220 pounds per square inch gauge [psig])[ix]. This is considered an average storage site and requires roughly one injection well for each 9,360 tonnes (10,320 short tons) of CO_2 injected per day. The assumed aquifer characteristics are tabulated in Table 10.

Table 10 - Deep Saline Aquifer Specification

Parameter	Units	Base Case
Pressure	MPa (psi)	8.4 (1,220)
Thickness	m (ft)	161 (530)
Depth	m (ft)	1,236 (4,055)
Permeability	md (μm^2)	22 (22)
Pipeline Distance	Km (miles)	80 (50)
Injection Rate per Well	Tonne (ton) CO_2/day	9,360 (10,320)

The cost metrics utilized in this study provide a best estimate of TS&M costs for a "typical" sequestration project, and may vary significantly based on variables such as terrain to be crossed by the pipeline, reservoir characteristics, and number of land owners from which sub-surface rights must be acquired. Raw capital and operating costs are derived from detailed cost metrics found in the literature, escalated to June 2007-year dollars using appropriate price indices. These costs were then verified against values quoted by industrial sources where possible. Where regulatory uncertainty exists or costs are undefined, such as liability costs and the acquisition of underground pore volume, analogous existing policies were used for representative cost scenarios.

The following subsections describe the sources and methodology used for each metric.

Cost Levelization

Capital and operating costs were levelized over a 30-year period and include both a 20% process contingency and 30% project contingency.

In several areas, such as Pore Volume Acquisition, Monitoring, and Liability, cost outlays occur over a longer time period, up to 100 years. In these cases a capital fund is established based on the net present value of the cost outlay, and this fund is then levelized similar to the other costs.

Transport Costs

CO_2 transport costs are broken down into three categories: pipeline costs, related capital expenditures, and O&M costs.

Pipeline costs are derived from data published in the Oil and Gas Journal's (O&GJ) annual Pipeline Economics Report for existing natural gas, oil, and petroleum pipeline project costs from 1991 to 2003. These costs are expected to be analogous to the cost of building a CO_2 pipeline[x]. The University of California performed a regression analysis to generate the following cost curves from the O&GJ data: (1) Pipeline Materials, (2) Direct Labor, (3) Indirect Costs, and (4) Right-of-way acquisition, with each represented as a function of pipeline length and diameter.

Storage Costs

Storage costs were broken down into five categories: (1) Site Screening and Evaluation, (2) Injection Wells, (3) Injection Equipment, (4) O&M Costs, and (5) Pore Volume Acquisition. With the exception of Pore Volume Acquisition, all of the costs were obtained from Economic Evaluation of CO_2 Storage and Sink Enhancement Options. These costs include all of the costs associated with determining, developing, and maintaining a CO_2 storage location, including site evaluation, well drilling, and the capital equipment required for distributing and injecting CO_2.

Pore Volume Acquisition costs are the costs associated with acquiring rights to use the sub-surface area where the CO_2 will be stored, i.e. the pore space in the geologic formation. These costs were based on recent research by Carnegie Mellon University which examined existing sub-surface rights acquisition as it pertains to natural gas storage[xi]. The regulatory uncertainty in this area combined with unknowns regarding the number and type (private or government) of property owners, require a number of "best engineering judgment" decisions to be made, as documented below under Cost Metrics.

Liability Protection

Liability Protection addresses the fact that if damages are caused by injection and long-term storage of CO_2, the injecting party may bear financial liability. Several types of liability protection schemes have been suggested for CO_2 storage, including Bonding, Insurance, and Federal Compensation Systems combined with either tort law (as with the Trans-Alaska Pipeline Fund), or with damage caps and preemption, as is used for nuclear energy under the Price Anderson Act[xii]. However, at present, a specific liability regime has yet to be dictated either at a Federal or (to our knowledge) State level. However, certain state governments have enacted legislation which assigns liability to the injecting party, either in perpetuity (Wyoming) or until ten years after the cessation of injection operations, pending reservoir integrity certification, at which time liability is turned over to the state (North Dakota and Louisiana)[xiii, xiv, xv]. In the case of Louisiana, a trust fund of five million dollars is established for each injector over the first ten years (120 months) of injection operations. This fund is then used by the state for CO_2 monitoring and, in the event of an at-fault incident, damage payments.

Liability costs assume that a bond must be purchased before injection operations are permitted in order to establish the ability and good will of an injector to address damages where they are deemed liable. A figure of five million dollars was used for the bond based on the Louisiana fund level. This bond level may be conservative, in that the Louisiana fund covers both liability and monitoring, but that fund also pertains to a certified reservoir where injection operations have ceased, having a reduced risk compared to active operations. The bond cost was not escalated.

Monitoring Costs

Monitoring costs were evaluated based on the methodology set forth in the IEA Greenhouse Gas R&D Programme's Overview of Monitoring Projects for Geologic Storage Projects report[xvi]. In this scenario, operational monitoring of the CO_2 plume occurs over thirty years (during plant operation) and closure monitoring occurs for the following fifty years (for a total of eighty years). Monitoring is via electromagnetic (EM) survey, gravity survey, and periodic seismic survey; EM and gravity surveys are ongoing while seismic survey occurs in years 1, 2, 5, 10, 15, 20, 25, and 30 during the operational period, then in years 40, 50, 60, 70, and 80 after injection ceases.

Thirty-Year, Current-Dollar, Levelized Cost of Electricity

The revenue requirement method of performing an economic analysis of a prospective power plant has been widely used in the electric utility industry. This method permits the incorporation of the various dissimilar components for a potential new plant into a single value that can be compared to various alternatives. The revenue requirement figure-of-merit in this report is COE levelized over a 30 year period and expressed in mills/kWh (numerically equivalent to dollars per megawatt hour [$/MWh]). The 30-year, current-dollar LCOE was calculated using a simplified equation derived from the NETL Power Systems Financial Model[xvii].

The equation used to calculate LCOE is as follows:

$$LCOE_P = \frac{(CCF_P)(TOC) + (LF)[(OC_{F1}) + (OC_{F2}) + \ldots] + (CF)(LF)[(OC_{V1}) + (OC_{V2}) + \ldots]}{(CF)(MWh)}$$

Where,

$LCOE_P$ =	levelized cost of electricity over P years, $/MWh
P =	levelization period (30 years)

CCF_P =	capital charge factor for a levelization period of P years
TOC =	total overnight cost, $
LF =	levelization factor
OC_{Fn} =	category n fixed operating cost for the initial year of operation (but expressed in "first-year-of-construction" year dollars)
CF =	plant capacity factor
OC_{Vn} =	category n variable operating cost at 100 percent CF for the initial year of operation (but expressed in "first-year-of-construction" year dollars)
MWh =	annual net megawatt-hours of power generated at 100 percent CF

All costs are expressed in June 2007 dollars, and the resulting LCOE is expressed in mixed year dollars.

In CO_2 capture cases, the LCOE for TS&M costs was added to the LCOE calculated using the above equation to generate a total cost including CO_2 capture, sequestration, and subsequent monitoring.

Although their useful life is usually well in excess of 30 years, a 30-year levelization period is typically used for large energy conversion plants and is the levelization period used in this study.

The technologies modeled in this study were categorized as IOU. The non-capture NGCC plants are categorized as low risk while the CO_2 capture cases are categorized as high risk. The resulting capital charge and levelization factors are shown in Table 11.

Table 11 - Economic Parameters for LCOE Calculation

	High Risk	Low Risk
CCF	0.1567	0.1502
Levelization Factor	1.4109	1.4326

The economic assumptions used to derive the CCFs are shown in Table 11 and Table 12. The difference between the high risk and low risk categories is manifested in the debt-to-equity ratio and the weighted cost of capital. The values used to generate the CCFs and levelization factors in this study are shown in Table 12 and Table 13.

Table 12 - Parameter Assumptions for Capital Charge Factors

Parameter	Value
TAXES	
Income Tax Rate	38% (Effective 34% Federal, 6% State)
Capital Depreciation	20 years, 150% declining balance
Investment Tax Credit	0%
Tax Holiday	0 years
FINANCING TERMS	
Repayment Term of Debt	15 years

Parameter	Value
Grace Period on Debt Repayment	0 years
Debt Reserve Fund	None
TREATMENT OF CAPITAL COSTS	
Capital Cost Escalation During Construction (nominal annual rate)	3.6%[17]
Distribution of Total Overnight Capital over the Capital Expenditure Period (before escalation)	3-Year Period: 10%, 60%, 30%
Working Capital	zero for all parameters
% of Total Overnight Capital that is Depreciated	100% *(this assumption introduces only a very small error even if a substantial amount of TOC is actually non-depreciable)*
INFLATION	
LCOE, O&M, Fuel Escalation (nominal annual rate) Escalation rates must be the same for LCOE approximation to be valid	3.0%[18] COE, O&M, Fuel

[17] A nominal average annual rate of 3.6% is assumed for escalation of capital costs during construction. This rate is equivalent to the nominal average annual escalation rate for process plant construction costs between 1947 and 2008 according to the *Chemical Engineering* Plant Cost Index.

[18] An average annual inflation rate of 3.0% is assumed. This rate is equivalent to the average annual escalation rate between 1947 and 2008 for the U.S. Department of Labor's Producer Price Index for Finished Goods, the so-called "headline" index of the various Producer Price Indices. (The Producer Price Index for the Electric Power Generation Industry may be more applicable, but that data does not provide a long-term historical perspective since it only dates back to December 2003.)

Table 13 - Financial Structure for Investor Owned Utility High and Low Risk Projects

Type of Security	% of Total	Current (Nominal) Dollar Cost	Weighted Current (Nominal) Cost	After Tax Weighted Cost of Capital
Low Risk				
Debt	50	4.5%	2.25%	
Equity	50	12%	6%	
Total			8.25%	7.39%
High Risk				
Debt	45	5.5%	2.475%	
Equity	55	12%	6.6%	
Total			9.075%	8.13%

4. Natural Gas Combined Cycle Plants Performance and Cost

This study evaluates the cost and performance of an existing NGCC plant retrofitted for carbon capture and sequestration using an advanced amine scrubber. The CO_2 capture range considered varies from 0% to 90%. Since these are existing units, it is assumed that the existing plant has been fully paid off, and the only capital outlay required is that for the CCS process (which includes both the chemical scrubber, CO_2 compression train, pipeline and storage wells). However ongoing fuel costs, as well as fixed and variable O&M, are accounted for.

The existing NGCC plant is based on the use of a GE Energy 7EA combustion turbine (1979 vintage) with the following performance characteristics:

Table 14 – GE 7EA Gas Turbine Combined Cycle Performance[xviii]

Gas Turbine Exhaust Temperature, ºF	999
Gas Turbine Pressure Ratio	12.7
Gas Turbine Exhaust Flow, lb/sec	660
Combined Cycle Heat Rate, Btu/kWh (LHV)	6,700
Combined Cycle Gas Turbine Power, MW	167 (2 x 7EA)
Combined Cycle Steam Turbine Power, MW	100.7[19]
Combined Cycle Total Power, MW	263.6

Each design is based on the use of a GE Energy 7EA combustion turbine, two heat recovery system generators (HRSGs) and one steam turbine generator. The NGCC cases that include CCS are based on the use of an Econamine FG Plus amine scrubbing system. The sizes of the NGCC designs were determined by the output of the assumed existing NGCC turbine shown in the above table.

[19] Condenser pressure = 1.2" Hg

4.1 NGCC Cases without CCS

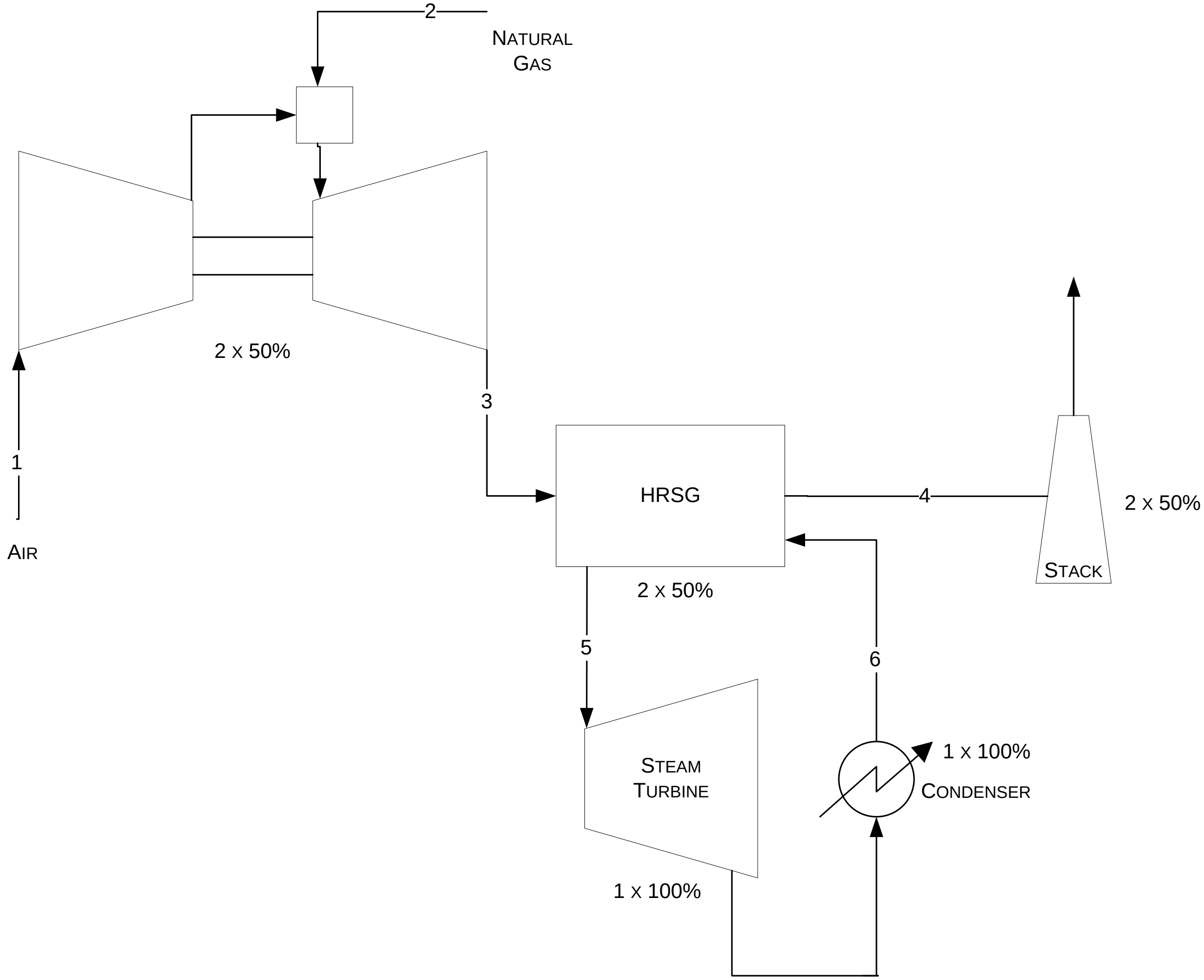
This section contains an evaluation of plant designs for two NGCC cases that do not include CCS. Case 1 refers to the NGCC plant located at the midwestern U.S. site, and Case 2 refers to the NGCC unit at the western USA site. Both plants include a single reheat, 2400 psig / 950 °F / 950 °F steam cycle.

4.1.1 Case 1 – Midwestern NGCC

In this section, the midwestern NGCC plant is described. The system description follows the block flow diagram (BFD) in Figure 10. A stream table, corresponding to the numbers listed on the BFD, is shown in Table 15. The BFD shows only one of the two combustion turbine/HRSG combinations, while the stream table shows totals for both process trains.

Ambient air (stream 1) and natural gas (stream 2) are combined in the gas turbine combustor. The flue gas exits the turbine at 1,000 °F (stream 3) and passes into the HRSG. The HRSG generates both the main steam and reheat steam for the steam turbine. Flue gas exits the HRSG and passes to the plant stack.

Figure 10 – Case 1 (Midwestern NGCC Plant)



Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown.

Table 15 – Case 1 (Midwestern NGCC) Stream Table

	1	2	3	4	5	6
V-L Mole Fraction						
Ar	0.0092	0.0000	0.0090	0.0090	0.0000	0.0000
CH_4	0.0000	0.9310	0.0000	0.0000	0.0000	0.0000
C_2H_6	0.0000	0.0320	0.0000	0.0000	0.0000	0.0000
C_3H_8	0.0000	0.0070	0.0000	0.0000	0.0000	0.0000
C_4H_{10}	0.0000	0.0040	0.0000	0.0000	0.0000	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0003	0.0100	0.0322	0.0322	0.0000	0.0000
H_2O	0.0099	0.0000	0.0710	0.0710	1.0000	1.0000
N_2	0.7732	0.0160	0.7493	0.7493	0.0000	0.0000
O_2	0.2074	0.0000	0.1385	0.1385	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	71,970	2,277	74,313	74,313	8,698	15,750
V-L Flowrate (kg/hr)	2,076,829	39,452	2,116,281	2,116,281	156,694	283,742
Solids Flowrate (kg/hr)	0	0	0	0	0	0
Temperature (°C)	15	38	538	116	510	38
Pressure (MPa, abs)	0.10	3.10	0.11	0.10	16.65	0.01
Enthalpy (kJ/kg)[A]	30.23	46.30	698.22	233.95	3,316.82	160.61
Density (kg/m^3)	1.2	22.2	0.4	0.9	53.1	992.9
V-L Molecular Weight	28.857	17.328	28.478	28.478	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	158,666	5,020	163,831	163,831	19,175	34,723
V-L Flowrate (lb/hr)	4,578,624	86,976	4,665,600	4,665,600	345,451	625,544
Solids Flowrate (lb/hr)	0	0	0	0	0	0
Temperature (°F)	59	100	1,001	242	950	101
Pressure (psia)	14.7	450.0	15.2	14.7	2,414.7	1.0
Enthalpy (Btu/lb)[A]	13.0	19.9	300.2	100.6	1,426.0	69.1
Density (lb/ft^3)	0.076	1.384	0.028	0.056	3.316	61.982

4.1.2 Case 1 Performance Results

The plant produces a net output of 257 MW at a net plant efficiency of 44.7 percent (HHV basis).

Overall plant performance is summarized in Table 16, which includes auxiliary power requirements.

Table 16 – Midwestern NGCC Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power	167,800
Steam Turbine Power	94,700
TOTAL POWER, kWe	**262,500**
AUXILIARY LOAD SUMMARY, kWe	
Condensate Pumps	90
Boiler Feedwater Pumps	1,150
Amine System Auxiliaries	0
CO_2 Compression	0
Circulating Water Pump	1,270
Ground Water Pumps	120
Cooling Tower Fans	670
SCR	10
Gas Turbine Auxiliaries	700
Steam Turbine Auxiliaries	100
Miscellaneous Balance of Plant	500
Transformer Losses	800
TOTAL AUXILIARIES, kWe	**5,410**
NET POWER, kWe	**257,090**
Net Plant Efficiency (HHV)	44.7%
Net Plant Efficiency (LHV)	49.6%
Net Plant Heat Rate (HHV), Btu/kWhr	7,629
Net Plant Heat Rate (LHV), Btu/kWhr	6,878
CONDENSER COOLING DUTY, MMBtu/h	**590**
CONSUMABLES	
Natural Gas Feed Flow, lb/hr	86,976
Thermal Input (HHV), kW_{th}	574,777
Thermal Input (LHV) , kW_{th}	518,235
Raw Water Withdrawal, gpm	1,304
Raw Water Consumption, gpm	1,010

Environmental Performance

The estimated air emissions are shown in Table 17. Operation of the turbine fueled by natural gas, coupled to a HRSG, results in very low NOx emissions and negligible amounts of particulate and SO_2. There are no mercury emissions in an NGCC plant.

The low level of NOx production (2.5 ppmvd at 15% O_2) is achieved by utilizing Selective Catalytic Reduction (SCR).

Table 17 – Midwestern NGCC Estimated Air Emissions

	lb/10^6 Btu	ton/year (85% capacity factor)	lb/MWh-net
SO_2	Negligible	Negligible	Negligible
NOx	0.009	66	0.069
Particulate	Negligible	Negligible	Negligible
Hg	Negligible	Negligible	Negligible
CO_2	118.5	865,479	904

The carbon balance is shown in Table 18. The carbon input to the plant consists of carbon in the air and the carbon in the natural gas. Carbon leaves the plant as CO_2 through the stack. The percent of total carbon sequestered is defined as the amount of carbon product produced divided by the carbon in the natural gas feedstock, expressed as a percentage.

% Captured = Carbon in Product for Sequestration / Carbon in the Natural gas

or

0/62,822 *100 = 0%

Table 18 – Midwestern NGCC Carbon Balance

Carbon In, lb/hr		Carbon Out, lb/hr	
Natural Gas	62,822	Stack Gas	63,444
Air (CO_2)	623	CO_2 Product	0
Total	63,444	Total	63,444

An overall water balance for the plant is shown in Table 19. Raw water is obtained from groundwater (50 percent) and from municipal sources (50 percent). Water demand represents the total amount of water required for a particular process. Some water is recovered within the process and is re-used as internal recycle. Raw water withdrawal is the difference between water demand and internal recycle. The difference between water withdrawal and process water discharge is defined as water consumption and can be represented by the portion of the raw water withdrawn that is evaporated, transpired, incorporated into products or otherwise not returned to the water source from which it was withdrawn. Water consumption represents the net impact of the plant process on the water source balance.

Table 19 – Midwestern NGCC Water Balance

Water Use	Water Demand, gpm	Internal Recycle, gpm	Raw Water Withdrawal, gpm	Process Water Discharge, gpm	Raw Water Consumption, gpm
Econamine	0	0	0	0	0
Condenser Makeup	13	0	13	0	13
BFW Makeup	13	0	13		
Cooling Tower	1,304	13	1,291	293	998
BFW Blowdown	0	13	-13		
Flue Gas Condensate	0	0	0		
CO_2 Product Condensate	0	0	0		
Total	**1,316**	**13**	**1,304**	**293**	**1,010**

An overall plant energy balance is provided in tabular form in Table 20. The power out is the combined combustion turbine and steam turbine power after generator losses.

Table 20 – Midwestern NGCC Overall Energy Balance

	HHV	Sensible + Latent	Power	Total
Heat In, MMBtu/hr				
Natural Gas	1,961	1	0	1,963
GT Air	0	60	0	60
Raw Water Makeup	0	18	0	18
Auxiliary Power	0	0	18	18
TOTAL	**1,961**	**78**	**18**	**2,058**
Heat Out, MMBtu/hr				
Cooling Tower Blowdown	0	8	0	8
Stack Gas	0	469	0	469
Condenser	0	586	0	586
Process Losses	0	100	0	100
Power	0	0	896	896
TOTAL	**0**	**1,162**	**896**	**2,058**

4.1.3 Case 1 Costs

The 30-year LCOE for Case 1 is shown in Table 21 below. It should be noted that since the existing plant is assumed to be fully paid off, there is no capital expenditure. The LCOE is composed strictly of fuel, fixed O&M, and variable O&M costs. A detailed summary of these operating costs is shown in Table 22.

The Case 1 O&M costs are levelized consistent with the levelization factor provided by the low-risk financial criteria as outlined in Table 11.

Table 21 – Case 1 (Midwestern NGCC) 30-Year Levelized Cost of Electricity

	$/MWh
Capital	0
Fixed O&M	9.94
Variable O&M	3.24
Fuel	48.09
Total	61.26

1st Year COE[20]	42.76

[20] The first year COE is the levelized cost of electricity, divided by the levelization factor.

Table 22 – Midwestern NGCC Operating Cost Summary

INITIAL & ANNUAL O&M EXPENSES

Cost Base (Jun):	2007
Heat Rate-net (Btu/kWh):	7,635
MWe-net:	257
Capacity Factor (%):	75%

OPERATING & MAINTENANCE LABOR

Operating Labor

Operating Labor Rate(base):	34.65	$/hour
Operating Labor Burden:	30.00	% of base
Labor O-H Charge Rate:	25.00	% of labor

Operating Labor Requirements(O.J.)per Shift:	1 unit/mod.	Total Plant
Skilled Operator	1.0	1.0
Operator	3.3	3.3
Foreman	1.0	1.0
Lab Tech's, etc.	1.0	1.0
TOTAL-O.J.'s	6.3	6.3

	Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost	$1,476,014	$5.741
Maintenance Labor Cost	$2,491,833	$9.692
Administrative & Support Labor	$991,962	$3.858
Property Taxes and Insurance	$6,763,808	$26.309
TOTAL FIXED OPERATING COSTS	**$11,723,617**	**$45.60**

VARIABLE OPERATING COSTS

						$/kWh-net
Maintenance Material Cost					$3,737,750	**$0.00317**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost		
Water (/1000 gallons)					$442,057	**$0.00037**
Chemicals						
MU & WT Chem.(lbs)					$421,384	$0.00036
MEA Solvent (ton)					$183,218	$0.00016
Activated Carbon (lb)					$102,157	$0.00009
Corrosion Inhibitor					$1,219	$0.00000
SCR Catalyst (m3)					$68,606	$0.00006
Ammonia (19% NH3) (ton)					$129,670	$0.00011
Subtotal Chemicals					**$906,254**	**$0.00077**
Other						
Supplemental Fuel (MBtu)					$0	$0.00000
Gases,N2 etc. (/100scf)					$0	$0.00000
L.P. Steam (/1000 pounds)					$0	$0.00000
Subtotal Other					**$0**	**$0.00000**
Waste Disposal						
Flyash (ton)					$0	$0.00000
Bottom Ash (ton)					$0	$0.00000
Subtotal Waste Disposal					**$0**	**$0.00000**
By-products						
Sulfur (tons)					$0	$0.00000
Subtotal By-products					**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS					**$5,086,061**	**$0.00431**
Fuel (MMBtu)	0	47,069	4.40	**$0**	**$75,593,257**	**$0.04809**

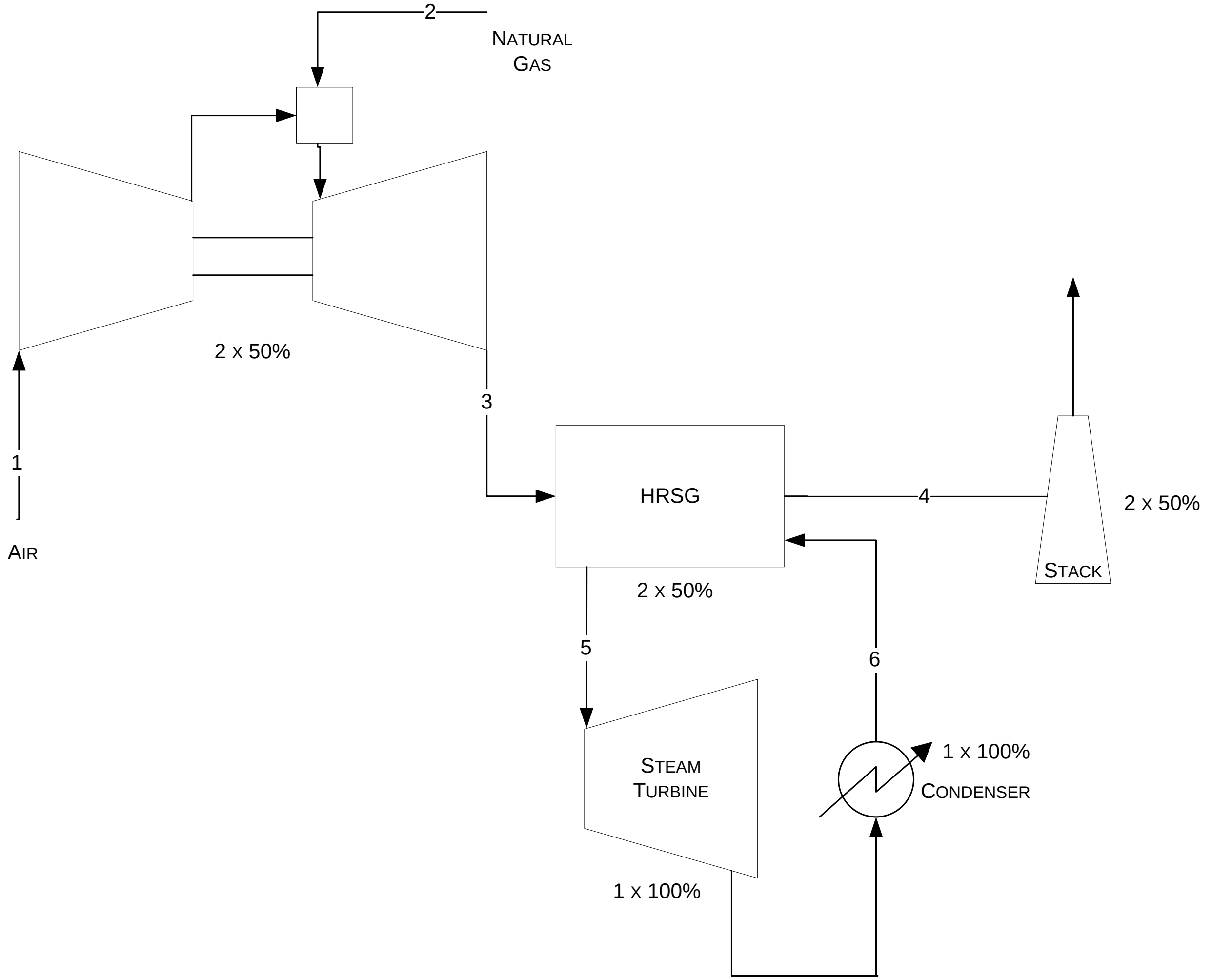
4.1.4 Case 2 – Western NGCC

In this section, the western NGCC plant is described. The system description follows the block flow diagram in Figure 11. A stream table, corresponding to the numbers listed on the BFD, is shown in Table 15. The BFD shows only one of the two combustion turbine/HRSG combinations, while the stream table shows totals for both process trains.

Ambient air (stream 1) and natural gas (stream 2) are combined in the gas turbine combustor. The flue gas exits the turbine at 1,000 °F (stream 3) and passes into the HRSG. The HRSG generates both the main steam and reheat steam for the steam turbine. Flue gas exits the HRSG and passes to the plant stack.

The combustion turbine performance for this case differs slightly from the rating shown in Table 14 due to operation at high elevation.

Figure 11 – Case 2 (Western NGCC Plant)



Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown.

Table 23 – Case 2 (Western NGCC) Stream Table

	1	2	3	4	5	6
V-L Mole Fraction						
Ar	0.0092	0.0000	0.0089	0.0089	0.0000	0.0000
CH_4	0.0000	0.9310	0.0000	0.0000	0.0000	0.0000
C_2H_6	0.0000	0.0320	0.0000	0.0000	0.0000	0.0000
C_3H_8	0.0000	0.0070	0.0000	0.0000	0.0000	0.0000
C_4H_{10}	0.0000	0.0040	0.0000	0.0000	0.0000	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0003	0.0100	0.0334	0.0334	0.0000	0.0000
H_2O	0.0099	0.0000	0.0732	0.0732	1.0000	1.0000
N_2	0.7732	0.0160	0.7484	0.7484	0.0000	0.0000
O_2	0.2074	0.0000	0.1361	0.1361	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	63,519	2,083	65,662	65,662	7,713	13,932
V-L Flowrate (kg/hr)	1,832,960	36,098	1,869,058	1,869,058	138,956	250,994
Solids Flowrate (kg/hr)	0	0	0	0	0	0
Temperature (°C)	6	38	538	113	510	32
Pressure (MPa, abs)	0.09	3.10	0.09	0.09	16.65	0.00
Enthalpy (kJ/kg)[A]	17.49	46.30	702.30	234.30	3,316.82	134.57
Density (kg/m^3)	1.1	22.2	0.4	0.8	53.1	995.0
V-L Molecular Weight	28.857	17.328	28.465	28.465	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	140,035	4,593	144,761	144,761	17,005	30,715
V-L Flowrate (lb/hr)	4,040,984	79,583	4,120,567	4,120,567	306,346	553,348
Solids Flowrate (lb/hr)	0	0	0	0	0	0
Temperature (°F)	42	100	1,000	236	950	90
Pressure (psia)	13.0	450.0	13.5	13.0	2,414.7	0.7
Enthalpy (Btu/lb)[A]	7.5	19.9	301.9	100.7	1,426.0	57.9
Density (lb/ft^3)	0.070	1.384	0.025	0.050	3.316	62.118

4.1.5 Case 2 Performance Results

The plant produces a net output of 238 MW at a net plant efficiency of 45.3 percent (HHV basis).

Overall plant performance is summarized in Table 24, which includes auxiliary power requirements.

Table 24 – Western NGCC Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power	156,400
Steam Turbine Power	86,800
TOTAL POWER, kWe	**243,200**
AUXILIARY LOAD SUMMARY, kWe	
Condensate Pumps	80
Boiler Feedwater Pumps	1,040
Amine System Auxiliaries	0
CO_2 Compression	0
Circulating Water Pump	1,120
Ground Water Pumps	100
Cooling Tower Fans	590
SCR	10
Gas Turbine Auxiliaries	700
Steam Turbine Auxiliaries	100
Miscellaneous Balance of Plant	500
Transformer Losses	740
TOTAL AUXILIARIES, kWe	**4,980**
NET POWER, kWe	**238,220**
Net Plant Efficiency (HHV)	45.3%
Net Plant Efficiency (LHV)	50.2%
Net Plant Heat Rate (HHV), Btu/kWhr	7,533
Net Plant Heat Rate (LHV), Btu/kWhr	6,792
CONDENSER COOLING DUTY, MMBtu/h	**510**
CONSUMABLES	
Natural Gas Feed Flow, lb/hr	79,583
Thermal Input (HHV), kW_{th}	525,920
Thermal Input (LHV) , kW_{th}	474,184
Raw Water Withdrawal, gpm	1,149
Raw Water Consumption, gpm	891

Environmental Performance

The estimated air emissions are shown in Table 25. Operation of the turbine fueled by natural gas, coupled to a HRSG, results in very low NOx emissions and negligible amounts of particulate and SO_2. There are no mercury emissions in an NGCC plant.

The low level of NOx production (2.5 ppmvd at 15% O_2) is achieved by utilizing Selective Catalytic Reduction (SCR).

Table 25 – Western NGCC Estimated Air Emissions

	lb/10^6 Btu	ton/year (85% capacity factor)	lb/MWh-net
SO_2	Negligible	Negligible	Negligible
NOx	0.009	60	0.068
Particulate	Negligible	Negligible	Negligible
Hg	Negligible	Negligible	Negligible
CO_2	118.5	791,662	893

The carbon balance is shown in Table 26. The carbon input to the plant consists of carbon in the air and the carbon in the natural gas. Carbon leaves the plant as CO_2 through the stack. The percent of total carbon sequestered is defined as the amount of carbon product produced divided by the carbon in the natural gas feedstock, expressed as a percentage.

% Captured = Carbon in Product for Sequestration / Carbon in the Natural gas

or

0/57,482 *100 = 0%

Table 26 – Western NGCC Carbon Balance

Carbon In, lb/hr		Carbon Out, lb/hr	
Natural Gas	57,482	Stack Gas	58,033
Air (CO_2)	551	CO_2 Product	0
Total	58,033	Total	58,033

An overall water balance for the plant is shown in Table 27. Raw water is obtained from groundwater (50 percent) and from municipal sources (50 percent). Water demand represents the total amount of water required for a particular process. Some water is recovered within the process and is re-used as internal recycle. Raw water withdrawal is the difference between water demand and internal recycle. The difference between water withdrawal and process water discharge is defined as water consumption and can be represented by the portion of the raw water withdrawn that is evaporated, transpired, incorporated into products or otherwise not returned to the water source from which it was withdrawn. Water consumption represents the net impact of the plant process on the water source balance.

Table 27 – Western NGCC Water Balance

Water Use	Water Demand, gpm	Internal Recycle, gpm	Raw Water Withdrawal, gpm	Process Water Discharge, gpm	Raw Water Consumption, gpm
Econamine	0	0	0	0	0
Condenser Makeup	11	0	11	0	11
BFW Makeup	11	0	11		
Cooling Tower	1,149	11	1,138	258	880
BFW Blowdown	0	11	-11		
Flue Gas Condensate	0	0	0		
CO_2 Product Condensate	0	0	0		
Total	**1,160**	**11**	**1,149**	**258**	**891**

An overall plant energy balance is provided in tabular form in Table 28. The power out is the combined combustion turbine and steam turbine power after generator losses.

Table 28 – Western NGCC Overall Energy Balance

	HHV	Sensible + Latent	Power	Total
Heat In, MMBtu/hr				
Natural Gas	1,795	1	0	1,796
GT Air	0	30	0	30
Raw Water Makeup	0	16	0	16
Auxiliary Power	0	0	17	17
TOTAL	**1,795**	**47**	**17**	**1,859**
Heat Out, MMBtu/hr				
Cooling Tower Blowdown	0	7	0	7
Stack Gas	0	415	0	415
Condenser	0	513	0	513
Process Losses	0	93	0	93
Power	0	0	830	830
TOTAL	**0**	**1,029**	**830**	**1,859**

4.1.6 Case 2 Costs

The 30-year LCOE for Case 2 is shown in Table 21 below. It should be noted that since the existing plant is assumed to be fully paid off, there is no capital expenditure. The LCOE is composed strictly of fuel, fixed O&M, and variable O&M costs. A detailed summary of these operating costs is shown in

Table 30.

The Case 2 O&M costs are levelized consistent with the levelization factor provided by the low-risk financial criteria as outlined in Table 11.

Table 29 – Case 2 (Western NGCC) 30-Year Levelized Cost of Electricity

	$/MWh
Capital	0
Fixed O&M	9.94
Variable O&M	3.24
Fuel	63.67
Total	76.85
1st Year COE[21]	53.64

[21] The first year COE is the levelized cost of electricity, divided by the levelization factor.

Table 30 – Western NGCC Operating Cost Summary

INITIAL & ANNUAL O&M EXPENSES

Cost Base (Jun):	2007
Heat Rate-net (Btu/kWh):	7,539
MWe-net:	238
Capacity Factor (%):	75%

OPERATING & MAINTENANCE LABOR							
Operating Labor							
Operating Labor Rate(base):	34.65	$/hour					
Operating Labor Burden:	30.00	% of base					
Labor O-H Charge Rate:	25.00	% of labor					
Operating Labor Requirements(O.J.)per Shift:	1 unit/mod.		Total Plant				
Skilled Operator	1.0		1.0				
Operator	3.3		3.3				
Foreman	1.0		1.0				
Lab Tech's, etc.	1.0		1.0				
TOTAL-O.J.'s	6.3		6.3				
						Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost						$1,367,677	$5.741
Maintenance Labor Cost						$2,308,937	$9.692
Administrative & Support Labor						$919,153	$3.858
Property Taxes and Insurance						$6,267,355	$26.309
TOTAL FIXED OPERATING COSTS						**$10,863,122**	**$45.60**
VARIABLE OPERATING COSTS							
							$/kWh-net
Maintenance Material Cost						$3,463,405	**$0.00317**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost			
Water (/1000 gallons)						$409,611	**$0.00037**
Chemicals							
MU & WT Chem.(lbs)						$390,455	$0.00036
MEA Solvent (ton)						$169,770	$0.00016
Activated Carbon (lb)						$94,659	$0.00009
Corrosion Inhibitor						$1,130	$0.00000
SCR Catalyst (m3)						$63,571	$0.00006
Ammonia (19% NH3) (ton)						$120,152	$0.00011
Subtotal Chemicals						**$839,737**	**$0.00077**
Other							
Supplemental Fuel (MBtu)						$0	$0.00000
Gases,N2 etc. (/100scf)						$0	$0.00000
L.P. Steam (/1000 pounds)						$0	$0.00000
Subtotal Other						**$0**	**$0.00000**
Waste Disposal							
Flyash (ton)						$0	$0.00000
Bottom Ash (ton)						$0	$0.00000
Subtotal Waste Disposal						**$0**	**$0.00000**
By-products							
Sulfur (tons)						$0	$0.00000
Subtotal By-products						**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS						**$4,712,752**	**$0.00431**
Fuel (MMBtu)	0	43,068	5.90	**$0**		**$92,747,587**	**$0.06367**

4.2 NGCC Cases with CCS

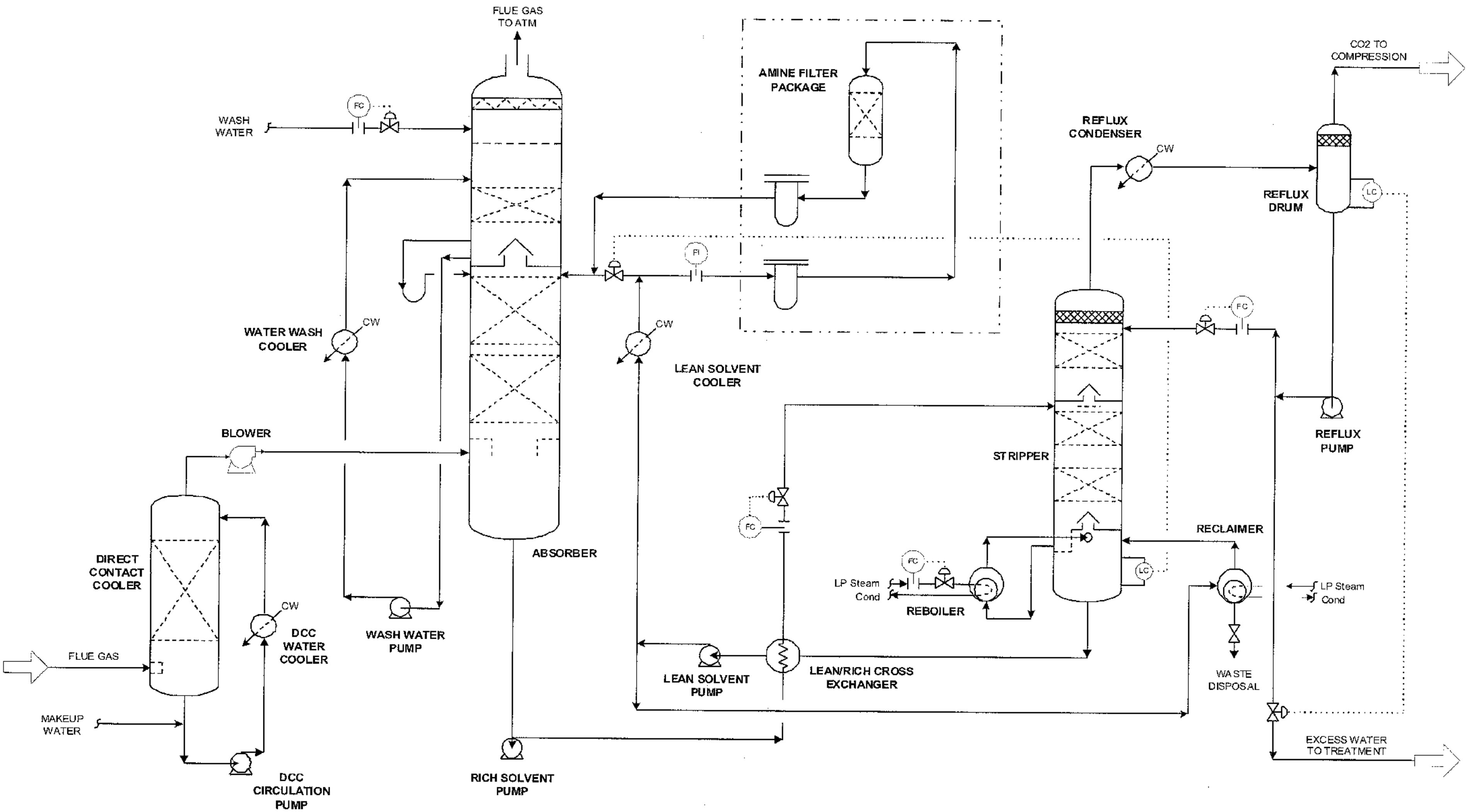
This section contains an evaluation of plant designs for two NGCC cases that include 90% CCS. Case 3 refers to the NGCC plant located at the midwestern USA site, and Case 4 refers to the NGCC unit at the western USA site. Both plants include a single reheat, 2400 psig / 950 °F / 950 °F cycle.

Carbon Dioxide Recovery Facility

A carbon dioxide recovery (CDR) facility is used in Cases 3 and 4 to remove 90 percent of the CO_2 in the flue gas exiting the HRSG, dry it, and compress it to meet pipeline conditions. It is assumed that all of the carbon in the natural gas is converted to CO_2. The CDR is comprised of flue gas supply, CO_2 absorption, solvent stripping and reclaiming, and CO_2 compression and drying.

The CO_2 absorption/stripping/solvent reclaim process for the CO_2 capture cases is based on the Econamine technology. A typical flow sheet is shown in Figure 12. The Econamine process uses a formulation of monoethanolamine (MEA) and a proprietary corrosion inhibitor to recover CO_2 from the flue gas. This process is designed to recover high-purity CO_2 from low pressure streams that contain O_2, such as flue gas from coal-fired power plants, gas turbine exhaust gas, and other waste gases.

Figure 12 - Fluor Econamine FG Plus Typical Flow Diagram[xix]



Flue Gas Cooling and Supply

The function of the flue gas cooling and supply system is to transport flue gases from the HRSG to the CO_2 absorption tower, and condition flue gas pressure, temperature, and moisture content so it meets the requirements of the Econamine process. Temperature and hence moisture content of the flue gas exiting the HRSG is reduced in the Direct Contact Flue Gas Cooler, where flue gas is cooled using cooling water.

The water condensed from the flue gas is collected in the bottom of the Direct Contact Flue Gas Cooler section and re-circulated to the top of the Direct Contact Flue Gas Cooler section via the Flue Gas Circulation Water Cooler, which rejects heat to the plant circulating water system. Level in the Direct Contact Flue Gas Cooler is controlled by directing the excess water to the cooling water return line. In the Direct Contact Flue Gas Cooler, flue gas is cooled beyond the CO_2 absorption process requirements to 33°C (91°F) to account for the subsequent flue gas temperature increase of 14°C (57°F) in the flue gas blower. Downstream from the Direct Contact Flue Gas Cooler, flue gas pressure is boosted in the flue gas blowers by approximately 0.01 MPa (2 psi) to overcome pressure drop in the CO_2 absorber tower.

Circulating Water System

Cooling water is provided from the NGCC plant circulating water system and returned to the cooling tower. The CDR facility requires a significant amount of water for flue gas cooling, water wash cooling, absorber intercooling, reflux condenser duty, reclaimer cooling, lean solvent cooler, and CO_2 compression interstage cooling.

CO_2 Absorption

The cooled flue gas enters the bottom of the CO_2 Absorber and flows up through the tower countercurrent to a stream of lean MEA-based solvent in the Econamine system. Approximately 90 percent of the CO_2 in the feed gas is absorbed into the lean solvent, while the remainder leaves the top of the absorber and flows into the water wash section of the tower. The lean solvent enters the top of the scrubber and absorbs the CO_2 from the flue gases.

Water Wash Section

The purpose of the Water Wash section is to minimize solvent losses due to mechanical entrainment and evaporation. The flue gas from the top of the CO_2 Absorption section is contacted with a re-circulating stream of water for the removal of most of the lean solvent. The scrubbed gases, along with unrecovered solvent, exit the top of the wash section for discharge to the atmosphere via the vent stack. The water stream from the bottom of the wash section is collected on a chimney tray. A portion of the water collected on the chimney tray spills over to the absorber section as water makeup for the amine with the remainder pumped via the Wash Water Pump and cooled by the Wash Water Cooler, and recirculated to the top of the CO_2 Absorber. The wash water level is maintained by water makeup from the Wash Water Makeup Pump.

Rich/Lean Amine Heat Exchange System

The rich solvent from the bottom of the CO_2 Absorber is preheated by the lean solvent from the Solvent Stripper in the Rich Lean Solvent Exchanger. The heated rich solvent is routed to the

Solvent Stripper for removal of the absorbed CO_2. The stripped solvent from the bottom of the Solvent Stripper is pumped via the Hot Lean Solvent Pumps through the Rich Lean Exchanger to the Solvent Surge Tank. Prior to entering the Solvent Surge Tank, a slipstream of the lean solvent is pumped via the Solvent Filter Feed Pump through the Solvent Filter Package to prevent buildup of contaminants in the solution. From the Solvent Surge Tank the lean solvent is pumped via the Warm Lean Solvent Pumps to the Lean Solvent Cooler for further cooling, after which the cooled lean solvent is returned to the CO_2 Absorber, completing the circulating solvent circuit.

Solvent Stripper
The purpose of the Solvent Stripper is to separate the CO_2 from the rich solvent feed exiting the bottom of the CO_2 Absorber. The rich solvent is collected on a chimney tray below the bottom packed section of the Solvent Stripper and routed to the Solvent Stripper Reboilers where the rich solvent is heated by steam, stripping the CO_2 from the solution. Steam is provided from the LP section of the steam turbine at about 0.51 MPa (74 psia) and 152°C (306°F). The hot wet vapor from the top of the stripper containing CO_2, steam, and solvent vapor, is partially condensed in the Solvent Stripper Condenser by cross exchanging the hot wet vapor with cooling water. The partially condensed stream then flows to the Solvent Stripper Reflux Drum where the vapor and liquid are separated. The uncondensed CO_2-rich gas is then delivered to the CO_2 product compressor. The condensed liquid from the Solvent Stripper Reflux Drum is pumped via the Solvent Stripper Reflux Pumps where a portion of condensed overhead liquid is used as make-up water for the Water Wash section of the CO_2 Absorber. The rest of the pumped liquid is routed back to the Solvent Stripper as reflux, which aids in limiting the amount of solvent vapors entering the stripper overhead system.

Solvent Stripper Reclaimer
A small slipstream of the lean solvent from the Solvent Stripper bottoms is fed to the Solvent Stripper Reclaimer for the removal of high-boiling nonvolatile impurities (heat stable salts), volatile acids and iron products from the circulating solvent solution. The solvent bound in the HSS is recovered by reaction with caustic and heating with steam. The solvent reclaimer system reduces corrosion, foaming, and fouling in the solvent system. The reclaimed solvent is returned to the Solvent Stripper and the spent solvent is pumped via the Solvent Reclaimer Drain Pump to the Solvent Reclaimer Drain Tank.

Steam Condensate
Steam condensate from the Solvent Stripper Reclaimer accumulates in the Solvent Reclaimer Condensate Drum and level controlled to the Solvent Reboiler Condensate Drum. Steam condensate from the Solvent Stripper Reboilers is also collected in the Solvent Reboiler Condensate Drum and returned to the steam cycle just downstream of the deaerator via the Solvent Reboiler Condensate Pumps.

Corrosion Inhibitor System
A proprietary corrosion inhibitor is continuously injected into the CO_2 Absorber rich solvent bottoms outlet line, the Solvent Stripper bottoms outlet line, and the Solvent Stripper top tray. This constant injection is to help control the rate of corrosion throughout the CO_2 recovery plant system.

Gas Compression and Drying System

In the compression section, the CO_2 is compressed to 2,215 psia by a six-stage centrifugal compressor. The discharge pressures of the stages were balanced to give reasonable power distribution and discharge temperatures across the various stages as shown in Table 31.

Table 31 – CO_2 Compressor Interstage Pressures

Stage	Outlet Pressure, psia
1	52
2	113
3	248
4	545
5	1,200
6	2,215

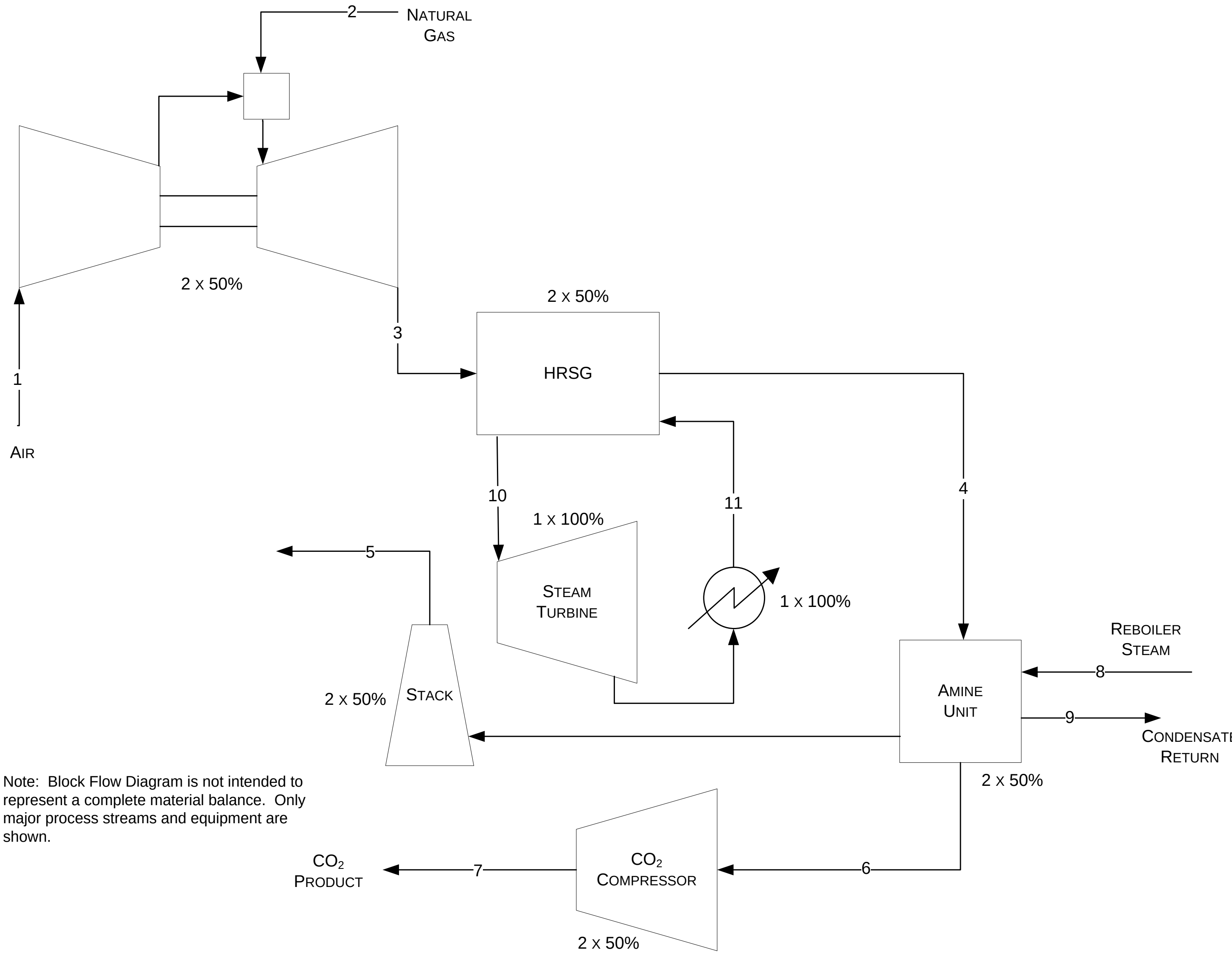
Power consumption for this large compressor was estimated assuming a polytropic efficiency of 86 percent. During compression to 2,215 psia, in the multiple-stage, intercooled compressor, the CO_2 stream is dehydrated to a dewpoint of -40°F with triethylene glycol. The virtually moisture-free CO_2 stream is delivered to the plant battery limit as sequestration-ready.

4.2.1 Case 3 – Midwestern NGCC with 90% CCS

In this section, the midwestern NGCC plant with 90% CCS is described. The system description follows the block flow diagram in Figure 13. A stream table, corresponding to the numbers listed on the block flow diagram, is shown in Table 15. The BFD shows only one of the two combustion turbine/HRSG combinations, while the stream table shows totals for both process trains.

Ambient air (stream 1) and natural gas (stream 2) are combined in the gas turbine combustor. The flue gas exits the turbine at 1,000 °F (stream 3) and passes into the HRSG. The HRSG generates both the main steam and reheat steam for the steam turbine. Flue gas exits the HRSG and passes to the amine unit. CO_2 is separated and compressed for pipeline transport and the remaining flue gas goes to the plant stack.

Figure 13 – Case 3 (Midwestern NGCC Plant with 90% CCS)



Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown.

Table 32 – Case 3 (Midwestern NGCC with 90% CCS) Stream Table

	1	2	3	4	5	6	7	8	9	10	11
V-L Mole Fraction											
Ar	0.0092	0.0000	0.0090	0.0090	0.0092	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CH_4	0.0000	0.9310	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_2H_6	0.0000	0.0320	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_3H_8	0.0000	0.0070	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_4H_{10}	0.0000	0.0040	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0003	0.0100	0.0322	0.0322	0.0033	0.9893	1.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0099	0.0000	0.0710	0.0710	0.0725	0.0107	0.0000	1.0000	1.0000	1.0000	1.0000
N_2	0.7732	0.0160	0.7493	0.7493	0.7722	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.2074	0.0000	0.1385	0.1385	0.1428	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	71,970	2,277	74,313	74,313	72,103	2,180	2,156	9,332	9,332	8,698	7,581
V-L Flowrate (kg/hr)	2,076,829	39,452	2,116,281	2,116,281	2,020,429	95,323	94,901	168,126	168,126	156,694	136,570
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	15	38	538	147	147	21	51	151	150	510	38
Pressure (MPa, abs)	0.10	3.10	0.11	0.10	0.10	0.16	15.27	0.49	0.47	16.65	0.01
Enthalpy (kJ/kg)[A]	30.23	46.30	698.22	266.50	271.66	26.65	-164.90	2,745.28	629.94	3,316.82	160.61
Density (kg/m^3)	1.2	22.2	0.4	0.8	0.8	2.9	653.5	2.6	917.1	53.1	992.9
V-L Molecular Weight	28.857	17.328	28.478	28.478	28.021	43.731	44.010	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	158,666	5,020	163,831	163,831	158,961	4,806	4,754	20,574	20,574	19,175	16,713
V-L Flowrate (lb/hr)	4,578,624	86,976	4,665,600	4,665,600	4,454,283	210,151	209,221	370,655	370,655	345,451	301,086
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	59	100	1,001	297	297	69	124	304	301	950	101
Pressure (psia)	14.7	450.0	15.2	14.7	14.7	23.5	2,214.7	71.0	68.5	2,414.7	1.0
Enthalpy (Btu/lb)[A]	13.0	19.9	300.2	114.6	116.8	11.5	-70.9	1,180.3	270.8	1,426.0	69.1
Density (lb/ft^3)	0.076	1.384	0.028	0.052	0.051	0.183	40.800	0.163	57.250	3.316	61.982

4.2.2 Case 3 Performance Results

The plant produces a net output of 217 MW at a net plant efficiency of 37.7 percent (HHV basis).

Overall plant performance is summarized in Table 33, which includes auxiliary power requirements.

Table 33 – Case 3 (Midwestern NGCC with 90% CCS) Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power	167,800
Steam Turbine Power	67,500
TOTAL POWER, kWe	**235,300**
AUXILIARY LOAD SUMMARY, kWe	
Condensate Pumps	40
Boiler Feedwater Pumps	1,150
Amine System Auxiliaries	5,000
CO_2 Compression	7,960
Circulating Water Pump	1,550
Ground Water Pumps	140
Cooling Tower Fans	810
SCR	10
Gas Turbine Auxiliaries	700
Steam Turbine Auxiliaries	100
Miscellaneous Balance of Plant	500
Transformer Losses	720
TOTAL AUXILIARIES, kWe	**18,680**
NET POWER, kWe	**216,620**
Net Plant Efficiency (HHV)	37.7%
Net Plant Efficiency (LHV)	41.8%
Net Plant Heat Rate (HHV), Btu/kWhr	9,054
Net Plant Heat Rate (LHV), Btu/kWhr	8,163
CONDENSER COOLING DUTY, MMBtu/h	**280**
CONSUMABLES	
Natural Gas Feed Flow, lb/hr	86,976
Thermal Input (HHV), kW_{th}	574,777
Thermal Input (LHV) , kW_{th}	518,235
Raw Water Withdrawal, gpm	1,596
Raw Water Consumption, gpm	1,244

Environmental Performance

The estimated air emissions are shown in Table 34. Operation of the turbine fueled by natural gas, coupled to a HRSG, results in very low NOx emissions and negligible amounts of particulate and SO_2. There are no mercury emissions in an NGCC plant.

The low level of NOx production (2.5 ppmvd at 15% O_2) is achieved by utilizing Selective Catalytic Reduction (SCR).

Table 34 – Case 3 (Midwestern NGCC with 90% CCS) Estimated Air Emissions

	lb/10^6 Btu	ton/year (85% capacity factor)	lb/MWh-net
SO_2	Negligible	Negligible	Negligible
NOx	0.009	60	0.08
Particulate	Negligible	Negligible	Negligible
Hg	Negligible	Negligible	Negligible
CO_2	11.9	81,457	107

The carbon balance is shown in Table 35. The carbon input to the plant consists of carbon in the air and the carbon in the natural gas. Carbon leaves the plant as CO_2 through the stack. The percent of total carbon sequestered is defined as the amount of carbon product produced divided by the carbon in the natural gas feedstock, expressed as a percentage.

% Captured = Carbon in Product for Sequestration / Carbon in the Natural gas

or

57,100/62,822 *100 = 90%

Table 35 – Case 3 (Midwestern NGCC with 90% CCS) Carbon Balance

Carbon In, lb/hr		Carbon Out, lb/hr	
Natural Gas	62,822	Stack Gas	6,344
Air (CO_2)	623	CO_2 Product	57,100
Total	63,444	Total	63,444

An overall water balance for the plant is shown in Table 36. Raw water is obtained from groundwater (50 percent) and from municipal sources (50 percent). Water demand represents the total amount of water required for a particular process. Some water is recovered within the process and is re-used as internal recycle. Raw water withdrawal is the difference between water demand and internal recycle. The difference between water withdrawal and process water discharge is defined as water consumption and can be represented by the portion of the raw water withdrawn that is evaporated, transpired, incorporated into products or otherwise not returned to the water source from which it was withdrawn. Water consumption represents the net impact of the plant process on the water source balance.

Table 36 – Case 3 (Midwestern NGCC with 90% CCS) Water Balance

Water Use	Water Demand, gpm	Internal Recycle, gpm	Raw Water Withdrawal, gpm	Process Water Discharge, gpm	Raw Water Consumption, gpm
Econamine	6	0	6	0	6
Condenser Makeup	13	0	13	0	13
BFW Makeup	13	0	13		
Cooling Tower	1,596	13	1,584	359	1,225
BFW Blowdown	0	13	-13		
Flue Gas Condensate	0	0	0		
CO_2 Product Condensate	0	4	-4		
Total	**1,609**	**13**	**1,596**	**359**	**1,244**

An overall plant energy balance is provided in tabular form in Table 37. The power out is the combined combustion turbine and steam turbine power after generator losses.

Table 37 – Case 3 (Midwestern NGCC with 90% CCS) Overall Energy Balance

	HHV	Sensible + Latent	Power	Total
Heat In, MMBtu/hr				
Natural Gas	1,961	1	0	1,963
GT Air	0	60	0	60
Raw Water Makeup	0	22	0	22
Auxiliary Power	0	0	64	64
TOTAL	**1,961**	**82**	**64**	**2,107**
Heat Out, MMBtu/hr				
CO_2	0	-15	0	-15
Cooling Tower Blowdown	0	10	0	10
Econamine Losses	0	354	0	354
CO_2 Compression Intercooling	0	42	0	42
Stack Gas	0	520	0	520
Condenser	0	279	0	279
Process Losses	0	115	0	115
Power	0	0	803	803
TOTAL	**0**	**1,304**	**803**	**2,107**

4.2.3 Case 3 (Midwestern NGCC with 90% CCS) Costs

The 30-year levelized cost of electricity (LCOE) for Case 3 is shown in Table 38 below. It should be noted that since the existing plant is assumed to be fully paid off, the only capital expenditure is that which is required for the CO_2 capture and compression island. A detailed summary of the capital and operating costs are shown in Table 39 and Table 40, respectively.

The Case 3 LCOE is based on the high-risk financial criteria as outlined in Table 11.

Table 38 – Case 3 (Midwestern NGCC with 90% CCS) 30-Year Levelized Cost of Electricity

	$/MWh
Capital	21.05
Fixed O&M	9.79
Variable O&M	3.19
Fuel	56.21
TS&M	3.77

Total	94.00
1st Year COE[22]	66.62

[22] The first year COE is the levelized cost of electricity, divided by the levelization factor.

Table 39 – Case 3 (Midwestern NGCC with 90% CCS) Capital Cost Summary

Acct		Equipment	Material	Labor		Sales	Bare Erected	Eng'g CM	Contingencies		TOTAL PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Tax	Cost $	H.O.& Fee	Process	Project	$	$/kW
1	COAL & SORBENT HANDLING	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2	COAL & SORBENT PREP & FEED	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	FEEDWATER & MISC. BOP SYSTEMS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.2	Syngas Cooling	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.4-4.9	Other gasification Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 4	**$0**	**$0**	**$0**	**$0**	**$0**	$0	**$0**	**$0**	**$0**	$0	**$0**
5A	GAS CLEANUP & PIPING	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5B	CO2 REMOVAL & COMPRESSION	$77,715	$0	$23,674	$0	$0	$101,389	$8,685	$17,886	$25,592	$153,551	$709
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.2-6.9	Combustion Turbine Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 6	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.2-7.9	SCR System, Ductwork and Stack	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 7	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 8	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9	COOLING WATER SYSTEM	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	ASH/SPENT SORBENT HANDLING SYS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11	ACCESSORY ELECTRIC PLANT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
12	INSTRUMENTATION & CONTROL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	IMPROVEMENTS TO SITE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	BUILDINGS & STRUCTURES	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL COST	**$77,715**	**$0**	**$23,674**	**$0**	**$0**	**$101,389**	**$8,685**	**$17,886**	**$25,592**	**$153,551**	**$709**
Owner's Costs												
6 Months Fixed O&M		$3,403,555										
1 Month Variable O&M		$357,120										
25% of 1 Months Fuel Cost at 100% CF		$1,574,860										
2% of TPC		$3,071,025										
Total		$8,406,559										
Inventory Capital												
60 day supply of fuel and consumables at 100% CF		$249,001										
0.5% of TPC (spare parts)		$767,756										
Total		$1,016,757										
Initial Cost for Catalyst and Chemicals		$763,596										
Land		$300,000										
Other Owner's Costs		$23,032,685										
Financing Costs		$4,145,883										
Total Overnight Cost (TOC)		$191,216,716										
TASC/TOC		1.078										
Total As-Spent Cost (TASC)		$206,131,620										

Table 40 – Case 3 (Midwestern NGCC with 90% CCS) Operating Cost Summary

INITIAL & ANNUAL O&M EXPENSES

Cost Base (Jun):	2007
Heat Rate-net (Btu/kWh):	9,061
MWe-net:	217
Capacity Factor (%):	75%

OPERATING & MAINTENANCE LABOR

Operating Labor

Operating Labor Rate(base):	34.65	$/hour
Operating Labor Burden:	30.00	% of base
Labor O-H Charge Rate:	25.00	% of labor

Operating Labor Requirements(O.J.)per Shift:	1 unit/mod.	Total Plant
Skilled Operator	1.0	1.0
Operator	3.3	3.3
Foreman	1.0	1.0
Lab Tech's, etc.	1.0	1.0
TOTAL-O.J.'s	6.3	6.3

	Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost	$1,243,666	$5.741
Maintenance Labor Cost	$2,099,580	$9.692
Administrative & Support Labor	$835,811	$3.858
Property Taxes and Insurance	$5,699,078	$26.309
TOTAL FIXED OPERATING COSTS	**$9,878,135**	**$45.60**

VARIABLE OPERATING COSTS

						$/kWh-net
Maintenance Material Cost					$3,149,370	**$0.00290**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost		
Water (/1000 gallons)					$372,470	**$0.00034**
Chemicals						
MU & WT Chem.(lbs)					$355,051	$0.00033
MEA Solvent (ton)					$154,376	$0.00014
Activated Carbon (lb)					$86,076	$0.00008
Corrosion Inhibitor					$1,027	$0.00000
SCR Catalyst (m3)					$57,807	$0.00005
Ammonia (19% NH3) (ton)					$109,258	$0.00010
Subtotal Chemicals					**$763,596**	**$0.00070**
Other						
Supplemental Fuel (MBtu)					$0	$0.00000
Gases,N2 etc. (/100scf)					$0	$0.00000
L.P. Steam (/1000 pounds)					$0	$0.00000
Subtotal Other					**$0**	**$0.00000**
Waste Disposal						
Flyash (ton)					$0	$0.00000
Bottom Ash (ton)					$0	$0.00000
Subtotal Waste Disposal					**$0**	**$0.00000**
By-products						
Sulfur (tons)					$0	$0.00000
Subtotal By-products					**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS					**$4,285,436**	**$0.00395**
Fuel (MMBtu)	0	47,069	4.40	**$0**	**$75,593,257**	**$0.05621**

4.2.4 Case 4 – Western NGCC with 90% CCS

In this section, the western NGCC plant with 90% CCS is described. The system description follows the block flow diagram in Figure 14. A stream table, corresponding to the numbers listed on the block flow diagram, is shown in Table 41. The BFD shows only one of the two combustion turbine/HRSG combinations, while the stream table shows totals for both process trains.

Ambient air (stream 1) and natural gas (stream 2) are combined in the gas turbine combustor. The flue gas exits the turbine at 1,000 °F (stream 3) and passes into the HRSG. The HRSG generates both the main steam and reheat steam for the steam turbine. Flue gas exits the HRSG and passes to the amine unit. CO_2 is separated and compressed for pipeline transport and the remaining flue gas goes to the plant stack.

The combustion turbine performance for this case differs slightly from the rating shown in Table 14 due to operation at high elevation.

Figure 14 – Case 4 (Western NGCC Plant with 90% CCS)

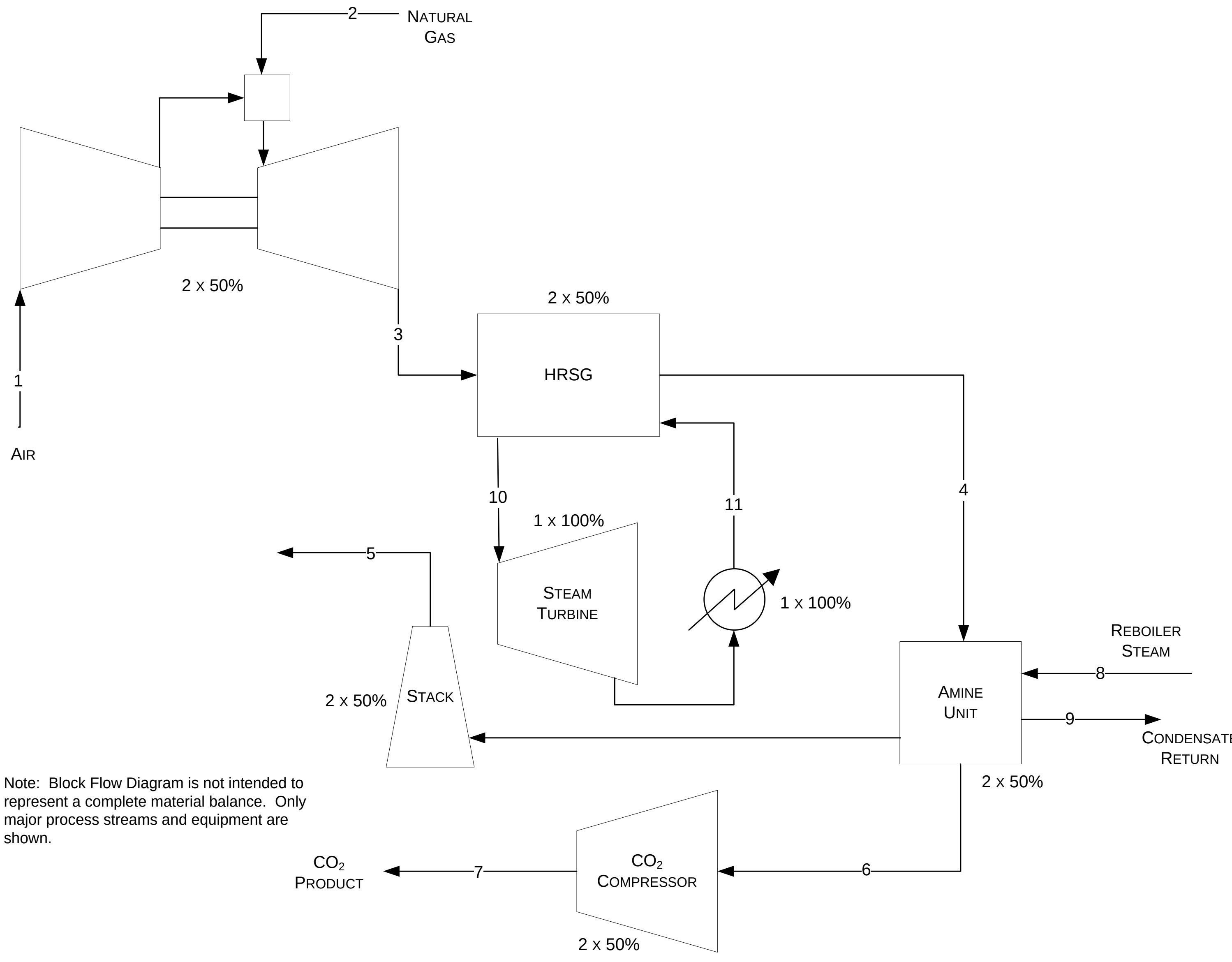


Table 41 – Case 4 (Western NGCC with 90% CCS) Stream Table

	1	2	3	4	5	6	7	8	9	10	11
V-L Mole Fraction											
Ar	0.0092	0.0000	0.0089	0.0089	0.0092	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CH_4	0.0000	0.9310	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_2H_6	0.0000	0.0320	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_3H_8	0.0000	0.0070	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_4H_{10}	0.0000	0.0040	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0003	0.0100	0.0334	0.0334	0.0034	0.9893	1.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0099	0.0000	0.0732	0.0732	0.0748	0.0107	0.0000	1.0000	1.0000	1.0000	1.0000
N_2	0.7732	0.0160	0.7484	0.7484	0.7722	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.2074	0.0000	0.1361	0.1361	0.1404	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	63,519	2,083	65,662	65,662	63,642	1,994	1,972	8,532	8,532	7,713	6,430
V-L Flowrate (kg/hr)	1,832,960	36,098	1,869,058	1,869,058	1,781,385	87,193	86,807	153,706	153,706	138,956	115,834
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	6	38	538	147	147	21	51	151	150	510	32
Pressure (MPa, abs)	0.09	3.10	0.09	0.09	0.09	0.16	15.27	0.49	0.47	16.65	0.00
Enthalpy (kJ/kg)[A]	17.49	46.30	702.30	270.04	275.57	26.65	-164.90	2,745.28	629.94	3,316.82	134.57
Density (kg/m^3)	1.1	22.2	0.4	0.7	0.7	2.9	653.5	2.6	917.1	53.1	995.0
V-L Molecular Weight	28.857	17.328	28.465	28.465	27.991	43.731	44.010	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	140,035	4,593	144,761	144,761	140,306	4,396	4,349	18,810	18,810	17,005	14,175
V-L Flowrate (lb/hr)	4,040,984	79,583	4,120,567	4,120,567	3,927,282	192,227	191,377	338,864	338,864	306,346	255,370
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	42	100	1,000	297	297	69	124	304	301	950	90
Pressure (psia)	13.0	450.0	13.5	13.0	13.0	23.5	2,214.7	71.0	68.5	2,414.7	0.7
Enthalpy (Btu/lb)[A]	7.5	19.9	301.9	116.1	118.5	11.5	-70.9	1,180.3	270.8	1,426.0	57.9
Density (lb/ft^3)	0.070	1.384	0.025	0.046	0.045	0.183	40.800	0.163	57.250	3.316	62.118

4.2.5 Case 4 Performance Results

The plant produces a net output of 200 MW at a net plant efficiency of 38.0 percent (HHV basis).

Overall plant performance is summarized in Table 42, which includes auxiliary power requirements.

Table 42 – Case 4 (Western NGCC with 90% CCS) Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power	156,400
Steam Turbine Power	60,600
TOTAL POWER, kWe	**217,000**
AUXILIARY LOAD SUMMARY, kWe	
Condensate Pumps	40
Boiler Feedwater Pumps	1,030
Amine System Auxiliaries	4,600
CO_2 Compression	7,280
Circulating Water Pump	1,380
Ground Water Pumps	130
Cooling Tower Fans	720
SCR	10
Gas Turbine Auxiliaries	700
Steam Turbine Auxiliaries	100
Miscellaneous Balance of Plant	500
Transformer Losses	660
TOTAL AUXILIARIES, kWe	**17,150**
NET POWER, kWe	**199,850**
Net Plant Efficiency (HHV)	38.0%
Net Plant Efficiency (LHV)	42.1%
Net Plant Heat Rate (HHV), Btu/kWhr	8,979
Net Plant Heat Rate (LHV), Btu/kWhr	8,096
CONDENSER COOLING DUTY, MMBtu/h	**230**
CONSUMABLES	
Natural Gas Feed Flow, lb/hr	79,583
Thermal Input (HHV), kW_{th}	525,920
Thermal Input (LHV) , kW_{th}	474,184
Raw Water Withdrawal, gpm	1,420
Raw Water Consumption, gpm	1,106

Environmental Performance

The estimated air emissions are shown in Table 43. Operation of the turbine fueled by natural gas, coupled to a HRSG, results in very low NOx emissions and negligible amounts of particulate and SO_2. There are no mercury emissions in an NGCC plant.

The low level of NOx production (2.5 ppmvd at 15% O_2) is achieved by utilizing Selective Catalytic Reduction (SCR).

Table 43 – Case 4 (Western NGCC with 90% CCS) Estimated Air Emissions

	$lb/10^6$ Btu	ton/year (85% capacity factor)	lb/MWh-net
SO_2	Negligible	Negligible	Negligible
NOx	0.009	55	0.079
Particulate	Negligible	Negligible	Negligible
Hg	Negligible	Negligible	Negligible
CO_2	11.8	74,509	106

The carbon balance is shown in Table 44. The carbon input to the plant consists of carbon in the air and the carbon in the natural gas. Carbon leaves the plant as CO_2 through the stack. The percent of total carbon sequestered is defined as the amount of carbon product produced divided by the carbon in the natural gas feedstock, expressed as a percentage.

% Captured = Carbon in Product for Sequestration / Carbon in the Natural gas

or

52,230/57,482 *100 = 90%

Table 44 – Case 4 (Western NGCC with 90% CCS) Carbon Balance

Carbon In, lb/hr		Carbon Out, lb/hr	
Natural Gas	57,482	Stack Gas	5,803
Air (CO_2)	551	CO_2 Product	52,230
Total	58,003	Total	58,003

An overall water balance for the plant is shown in Table 45. Raw water is obtained from groundwater (50 percent) and from municipal sources (50 percent). Water demand represents the total amount of water required for a particular process. Some water is recovered within the process and is re-used as internal recycle. Raw water withdrawal is the difference between water demand and internal recycle. The difference between water withdrawal and process water discharge is defined as water consumption and can be represented by the portion of the raw water withdrawn that is evaporated, transpired, incorporated into products or otherwise not returned to the water source from which it was withdrawn. Water consumption represents the net impact of the plant process on the water source balance.

Table 45 – Case 4 (Western NGCC with 90% CCS) Water Balance

Water Use	Water Demand, gpm	Internal Recycle, gpm	Raw Water Withdrawal, gpm	Process Water Discharge, gpm	Raw Water Consumption, gpm
Econamine	6	0	6	0	6
Condenser Makeup	11	0	11	0	11
BFW Makeup	11	0	11		
Cooling Tower	1,420	11	1,409	319	1,089
BFW Blowdown	0	11	-11		
Flue Gas Condensate	0	0	0		
CO_2 Product Condensate	0	4	-4		
Total	**1,431**	**11**	**1,420**	**319**	**1,106**

An overall plant energy balance is provided in tabular form in Table 46. The power out is the combined combustion turbine and steam turbine power after generator losses.

Table 46 – Case 4 (Western NGCC with 90% CCS) Overall Energy Balance

	HHV	Sensible + Latent	Power	Total
Heat In, MMBtu/hr				
Natural Gas	1,795	1	0	1,796
GT Air	0	30	0	30
Raw Water Makeup	0	19	0	19
Auxiliary Power	0	0	59	59
TOTAL	**1,795**	**51**	**59**	**1,904**
Heat Out, MMBtu/hr				
CO_2	0	-14	0	-14
Cooling Tower Blowdown	0	9	0	9
Econamine Losses	0	323	0	323
CO_2 Compression Intercooling	0	38	0	38
Stack Gas	0	465	0	465
Condenser	0	234	0	234
Process Losses	0	107	0	107
Power	0	0	740	740
TOTAL	**0**	**1,163**	**740**	**1,904**

4.2.6 Case 4 (Western NGCC with 90% CCS) Costs

The 30-year levelized cost of electricity (LCOE) for Case 4 is shown in Table 47 below. It should be noted that since the existing plant is assumed to be fully paid off, the only capital expenditure is that which is required for the CO_2 capture and compression island. A detailed summary of the capital and operating costs are shown in Table 48 and Table 49, respectively.

The Case 4 LCOE is based on the high-risk financial criteria as outlined in Table 11.

Table 47 – Case 4 (Western NGCC with 90% CCS) 30-Year Levelized Cost of Electricity

	$/MWh
Capital	21.48
Fixed O&M	9.79
Variable O&M	3.19
Fuel	74.75
TS&M	3.70
Total	112.91

1st Year COE[23]	80.03

[23] The first year COE is the levelized cost of electricity, divided by the levelization factor.

Table 48 – Case 4 (Western NGCC with 90% CCS) Capital Cost Summary

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
2	COAL & SORBENT PREP & FEED	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
3	FEEDWATER & MISC. BOP SYSTEMS	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.2	Syngas Cooling	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	ASU/Oxidant Compression	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.4-4.9	Other gasification Equipment	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 4	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
5A	GAS CLEANUP & PIPING	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
5B	CO2 REMOVAL & COMPRESSION	$73,014	$0	$22,242	$0	$0	**$95,255**	$8,159	$16,804	$24,044	**$144,262**	$722
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
6.2-6.9	Combustion Turbine Other	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 6	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
7.2-7.9	SCR System, Ductwork and Stack	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 7	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 8	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
9	COOLING WATER SYSTEM	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
10	ASH/SPENT SORBENT HANDLING SYS	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
11	ACCESSORY ELECTRIC PLANT	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
12	INSTRUMENTATION & CONTROL	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
13	IMPROVEMENTS TO SITE	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
14	BUILDINGS & STRUCTURES	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	TOTAL COST	**$73,014**	**$0**	**$22,242**	**$0**	**$0**	**$95,255**	**$8,159**	**$16,804**	**$24,044**	**$144,262**	**$722**
Owner's Costs												
6 Months Fixed O&M		$3,114,083										
1 Month Variable O&M		$329,473										
25% of 1 Months Fuel Cost at 100% CF		$1,932,241										
2% of TPC		$2,885,237										
Total		$8,261,034										
Inventory Capital												
60 day supply of fuel and consumables at 100% CF		$229,724										
0.5% of TPC (spare parts)		$721,309										
Total		$951,033										
Initial Cost for Catalyst and Chemicals		$704,481										
Land		$300,000										
Other Owner's Costs		$21,639,281										
Financing Costs		$3,895,070										
Total Overnight Cost (TOC)		$180,012,769										
TASC/TOC		1.078										
Total As-Spent Cost (TASC)		$194,053,765										

Table 49 – Case 4 (Western NGCC with 90% CCS) Operating Cost Summary

INITIAL & ANNUAL O&M EXPENSES						Cost Base (Jun):	2007
						Heat Rate-net (Btu/kWh):	8,987
						MWe-net:	200
						Capacity Factor (%):	75%
OPERATING & MAINTENANCE LABOR							
Operating Labor							
Operating Labor Rate(base):	34.65	$/hour					
Operating Labor Burden:	30.00	% of base					
Labor O-H Charge Rate:	25.00	% of labor					
			Total				
Operating Labor Requirements(O.J.)per Shift:	1 unit/mod.		Plant				
Skilled Operator	1.0		1.0				
Operator	3.3		3.3				
Foreman	1.0		1.0				
Lab Tech's, etc.	1.0		1.0				
TOTAL-O.J.'s	6.3		6.3				
						Annual Cost	Annual Unit Cost
						$	$/kW-net
Annual Operating Labor Cost						$1,147,386	$5.741
Maintenance Labor Cost						$1,937,037	$9.692
Administrative & Support Labor						$771,106	$3.858
Property Taxes and Insurance						$5,257,874	$26.309
TOTAL FIXED OPERATING COSTS						**$9,113,403**	**$45.60**
VARIABLE OPERATING COSTS							
							$/kWh-net
Maintenance Material Cost						$2,905,556	**$0.00268**
Consumables	Consumption		Unit	Initial			
	Initial	/Day	Cost	Cost			
Water (/1000 gallons)						$343,635	**$0.00032**
Chemicals							
MU & WT Chem.(lbs)						$327,564	$0.00030
MEA Solvent (ton)						$142,425	$0.00013
Activated Carbon (lb)						$79,412	$0.00007
Corrosion Inhibitor						$948	$0.00000
SCR Catalyst (m3)						$53,331	$0.00005
Ammonia (19% NH3) (ton)						$100,800	$0.00009
Subtotal Chemicals						**$704,481**	**$0.00065**
Other							
Supplemental Fuel (MBtu)						$0	$0.00000
Gases,N2 etc. (/100scf)						$0	$0.00000
L.P. Steam (/1000 pounds)						$0	$0.00000
Subtotal Other						**$0**	**$0.00000**
Waste Disposal							
Flyash (ton)						$0	$0.00000
Bottom Ash (ton)						$0	$0.00000
Subtotal Waste Disposal						**$0**	**$0.00000**
By-products							
Sulfur (tons)						$0	$0.00000
Subtotal By-products						**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS						**$3,953,671**	**$0.00365**
Fuel (MMBtu)	0	43,068	5.90		**$0**	**$92,747,587**	**$0.07475**

5. RECOMMENDATIONS FOR FUTURE WORK

A concept currently being considered for CCS in NGCC units is to recycle CO_2 from the capture island back to the turbine compressor inlet. This would minimize the amount of oxygen and increase the CO_2 concentration in the flue gas that is fed to the amine unit.

This concept may require turbine modifications, due to the changing gas composition being expanded through the machine (increased amount of CO_2). While this type of turbine modification may be acceptable for greenfield units, it was assumed for this study that a plant will not want to make any modifications to their existing turbine, which will add extra project cost.

Future work may consider this CO_2 recycle loop (back to the turbine compressor inlet), to determine the resulting cost and performance. If there is a performance improvement in the cycle, this may also provide insight into how much a plant may be willing to spend on the needed turbine upgrades, before the COE benefit disappears.

6. REFERENCES

i “Carbon Dioxide Emissions from the Generation of Electric Power in the United States,” http://www.eia.doe.gov/cneaf/electricity/page/co2_report/co2report.html#electric

ii “Assessment of Power Plants that Meet Proposed Greenhouse Gas Emission Performance Standards,” http://www.netl.doe.gov/energy-analyses/pubs/CA_GHG_Grol_042310.pdf

iii Herzog, Howard J., “The Economics of CO_2 Separation and Capture,” MIT Energy Laboratory

iv “Merit Shop Wage & Benefit Survey,” PAS, Inc., http://www.pas1.com/

v Quality Guidelines for Energy System Studies, prepared by DOE NETL Office of Systems and Policy Support, June 4, 2003

vi Association for the Advancement of Cost Engineering International, AACEI (1997). “Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Process Industries,” AACE International Recommended Practice No. 18R-97 (revised June 15, 1998). http://www.aacei.org/technical/rps/18r-97.pdf

vii Smith, Lawrence A., Gupta, Neeraj, Sass, Bruce M. and Bubenik, Thomas A., “Engineering and Economic Assessment of Carbon Dioxide Sequestration in Saline Formations,” Battelle Memorial Institute, 2001

viii Ciferno, Jared P. and McIlvried, Howard, “CO_2 Flow Modeling and Pipe Diameter Determination,” February, 2003

ix Economic Evaluation of CO_2 Storage and Sink Enhancement Options, Tennessee Valley Authority, NETL and EPRI, December 2002

x Parker, N., “Using Natural Gas Transmission Pipeline Costs to Estimate Hydrogen Pipeline Costs,” Institute of Transportation Studies, University of California, Davis, CA, 2004.

xi Gresham, R. L., Apt, J., et. al, “Implications of Compensating Property-Owners for Geologic Sequestration of CO2,” Department of Engineering and Public Policy, Carnegie Mellon University, Pittsburgh, PA, 1999.

xii Klass, A.B., Wilson, E.J., “Climate Change and Carbon Sequestration: Assessing a Liability Regime for Long-Term Storage of Carbon Dioxide,” 58 Emory Law Journal 103, 2008

xiii Senate Bill No. 2095, 61st Legislative Assembly of North Dakota, January 6th, 2009

xiv House Bill No. 661, Louisiana House of Representatives Regular Session, 2009

xv Enrolled Act No. 20 (Original House Bill No. 58), 60th Legislature of the State of Wyoming, General Session, 2009

xvi Overview of Monitoring Requirements for Geologic Storage Projects. IEA Greenhouse Gas R&D Programme, Report Number PH4/29, November 2004

xvii Power Systems Financial Model Version 5.0, September 2006 xviii Gas Turbine World 2009 Performance Specs, 26th Edition

xix Improvement in Power Generation with Post-Combustion Capture of CO_2, IEA Greenhouse Gas R&D Programme, Report PH4/33, November 2004